COMMONWEALTH OF MASSACHUSETTS

OFFICE OF CONSUMER AFFAIRS AND BUSINESS REGULATION

DIVISION OF ENERGY RESOURCES

DOER Report: 1998 Market Monitor

An Annual Report to the Great and General Court on the Status of Restructured Electricity Markets in Massachusetts

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This report is also posted on DOER's website at http://www.state.ma.us/doer

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EXECUTIVE SUMMARY

In 1998, the electric industry in Massachusetts was restructured, resulting in major changes to the pricing and provision of electricity to consumers. The year marked the beginning of the industry's transition from a highly regulated, vertically integrated monopoly structure to one that allows retail customers to choose among competitive power suppliers. This dramatic transformation was the result of the Electric Utility Restructuring Act (Chapter 164 of the Acts and Resolves of 1997) ("the Act"), that was signed into law by Governor A. Paul Cellucci on November 25, 1997.

The Act provides the framework for the evolution of a competitive electric industry in Massachusetts. Its primary goals are to reduce electricity prices, provide retail customers with a choice of power suppliers, maintain the reliability of the electric system, improve distribution performance and ensure consumer protection and education.

In order to monitor the progress of electric industry restructuring, the Legislature requires the Division of Energy Resources (DOER) to report periodically on electricity prices and price disparities, competitive market developments, and electric system reliability (M.G.L. c. 25A §§ 7, 11D, 11E). DOER presents its major findings for calendar year 1998 below.

1998 HIGHLIGHTS

1. Consumers Saved Almost $450 million in 1998.

The mandatory rate reductions of 10% resulted in approximately $450 million in savings for distribution company customers. Moreover, four of the eight affected distribution companies were able to offer more than the required 10% discount during some months of the year, and one company was able to give customers up to a 19% rate cut. Over the ten months from March through December 1998, the savings from the mandatory 10% rate cut were, on average, approximately $77 per residential customer, $756 per commercial customer, and $8,327 per industrial customer.

2. The First Year of Restructuring Did Not Change Price Disparities.

A comparison of 1997 and 1998 retail prices among the eight distribution companies showed statistically insignificant changes in price disparity. The mandatory rate reductions lowered overall rates about the same amount for each company.

3. Utilities Divested Almost 90% of Power Generating Plants.

At the end of 1998, the distribution companies had either completed or were in the process of completing the divestiture of their non-nuclear generation assets. The sales resulted in nearly a 30% reduction in stranded costs statewide, although the accomplishment of those savings varied significantly from one distribution company to another.

4. Competitive Retail Market Developed Slowly.

Several issues during 1998 led to slow growth in the competitive retail market. Impediments included low "standard offer" generation prices, the threat of a November 1998 referendum to repeal the Act, and delayed implementation of the bid-based competitive wholesale market. Nevertheless, in 1998, the DTE finalized the procedures and rules for registering competitive suppliers and brokers and licensed 22 competitive service providers. Registration is an important safeguard to protect consumers from fraudulent suppliers.

5. Competitive Suppliers Focused on Large Commercial and Industrial Customers.
By the first quarter of 1999, competitive suppliers provided 1.3% of distribution company retail electricity sales; however, this represented only 0.13% of the total number of customers. This imbalance implies that competitive suppliers focused on securing large industrial and commercial customers. In many cases, suppliers captured these customers through aggregation groups. The majority of customers, particularly residential, remained on standard offer or default generation service.

6. Municipal and other Aggregation Groups Formed.
The Act provided for formation of different types of aggregated groups to buy electricity. In particular, the Act gave municipal governments special rights to aggregate. In 1998, several cities and towns made progress toward becoming municipal aggregators. Other types of private and non-profit aggregation groups also formed to increase the buying power of participating consumers and reduce their transaction costs. Examples of such groups include the Health and Educational Facilities Authority, the Massachusetts Municipal Association, and chambers of commerce.

7. Distribution Company Acquisitions Were Proposed.
Three mergers or acquisitions were announced in the first year of restructuring. BEC Energy is seeking to merge with Commonwealth Energy System. Under the deal, a new holding company, NStar, will be created. National Grid Group is seeking to acquire New England Electric System (NEES). In the first quarter of 1999, NEES announced it would acquire Eastern Utilities Associates (EUA). These proposed realignments reflect regulatory pressure to reduce distribution costs and the reduced risk profile of companies that have divested their generation assets. Requisite federal and state approvals are required.

8. Reliability of the Electric System Remained a Top Priority.
The Independent System Operator of New England (ISO-New England) assumed responsibility for operation of the New England bulk power market from the New England Power Pool (NEPOOL) in July 1997. Reliability of the bulk power system is the cornerstone of ISO-New England's operations. Procedures intended to maintain high standards for system reliability were put in place. DOER estimates that New England will have the necessary generation plants and resources to meet future summer electricity demand.

9. Over 30,000 Megawatts of New Power Plants were Proposed.
Developers announced plans to build over 30,000 MW of new generation capacity across New England. While not all proposals will come to fruition, the increased competition from these new plants will force some of the existing, less efficient plants into retirement. Additionally, the almost exclusive use of natural gas and other low emission fuels in these proposed plants will reduce air pollution and provide customers with "clean" generation choices.

10. A Class Action Law Suit Was Filed.
In March 1998, a group of retail customers of Massachusetts electric distribution companies filed a class action suit on behalf of all retail customers. The suit sought a declaratory judgment from the Supreme Judicial Court (SJC) against distribution companies, the Department of Telecommunication and Energy (DTE), the DOER, and the Massachusetts Technology Park Corporation (MTPC). The complaint alleged that the Restructuring Act's requirement that distribution companies include in their rates mandatory charges for energy efficiency and renewable energy fund activities was unconstitutional. A decision in the case is expected in 2000.

FOCUS OF THE REPORT

This report is DOER's first annual assessment of certain results of Massachusetts' electric industry restructuring. As required by the Act, DOER will report annually on electricity prices and price disparities among customer classes, regions of the commonwealth and distribution companies. A comparison of Massachusetts' retail prices with those in other states is also given. The report also provides an overview of market developments that occurred in 1998 as a result of restructuring, and a discussion on the status of the reliability of the electric system. Finally, DOER includes its views on likely future market developments.

REPORT OUTLINE

Section I describes the genesis of the Act. The Act's goals and key provisions are highlighted.

Section II presents a review of the 10% mandated price reductions made by distribution companies. This section also highlights and analyzes the disparities of the price components among the Massachusetts distribution companies. In addition, there is a comparison and brief explanation of Massachusetts electricity prices compared to the United States and the other New England states.

Section III examines competitive market developments. Stranded cost reductions and utility divestitures of power generation assets are discussed. This section includes brief descriptions of events that affected the wholesale market as well as initial progress made towards retail market competition.

Section IV assesses the reliability of the electric system at the wholesale and retail distribution level. It discusses the role of the Independent System Operator of New England (ISO-NE) and the changes at the wholesale market, particularly the proposals to build 30,000-plus megawatts of new generation capacity in New England. Distribution reliability issues are also highlighted.

Section V lists DOER's assessment of likely future developments in the restructured electric industry.

I. THE RESTRUCTURING ACT

In November 1997, the Massachusetts Legislature passed "An Act Relative to Restructuring The Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein" (M.G.L., C. 164, Acts of 1997), throughout this report referred to as "the Act." Governor Cellucci signed the bill into law November 25, 1997, making Massachusetts one of the first states to restructure its electric industry. (Appendix A gives a history of milestones in Massachusetts' electric restructuring leading up to the Act.)

The primary reason for the change was the high cost of electricity in Massachusetts as compared to other states. Historically, Massachusetts has had one of the highest average retail rates in the United States. In 1997, Massachusetts had the fifth highest average retail electricity price,[1] in the country at 10.5 cents per kilowatt-hour. The national average was 6.85 cents per kilowatt-hour.[2] These high costs not only created significant adverse effects on consumers in general, but also prevented many Massachusetts businesses from being able to compete with businesses in lower cost regions of the country.

Another reason was the fact that electric generation was no longer exclusively being provided by vertically integrated utility companies. Federal initiatives, such as the Public Utility Regulatory Act of 1978 (PURPA), allowed so-called Independent Power Producers (IPP's) to own and operate generation plants. The Energy Policy Act of 1992 furthered this initiative by giving independent generators access to transmission services and wholesale power markets. It had become clear that power generation need no longer be part of the monopoly utility. Due to the unique physical and operational characteristics of the transmission and distribution systems, these elements of the electricity market would remain natural monopolies.

1.1 Restructuring Goals

To analyze how the Act affects the Massachusetts electric industry, electricity prices, and system reliability, it is necessary to understand the underlying goals of the Act and its key components. The basic goals were:

Create lower prices for electricity for Massachusetts residents and businesses;
Ensure full and fair competition in electricity generation;
Provide retail choice of suppliers to all customers;
Maintain system reliability and improve distribution performance;
Maintain and enhance public benefits (low-income discounts, energy efficiency, and an expanded role for renewable energy);
Ensure consumer protections and education; and
Provide an orderly and expeditious transition.

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[1] Unless otherwise noted electricity prices are defined as the average price paid per kWh of electricity. It is determined by dividing the total revenue received by the total amount of electricity sold and reported in cents/kWh. Individual customer's prices may differ substantially from the average.

[2] U.S. Department of Energy (DOE), Energy Information Administration (EIA), "Electric Power Monthly March 1999," Table 55, p.67.

1.2 Key Provisions of the Restructuring Act

Retail Choice of Power Supplier: Most dramatically, the Act allowed for competition among generators to provide power to retail customers. Beginning on March 1, 1998, affected distribution company customers could choose their generation (power) supplier. Previously, the traditional, vertically integrated utility companies controlled all aspects of electricity – generation, transmission, and distribution. Customers were captive and had very few alternatives to reduce their electricity costs or tailor their electricity usage to their individual economic needs. The investor-owned utilities (now called distribution companies) continue to be responsible for the transmission and distribution of the power. Transmission and distribution of electricity, the “wires” business, remain regulated functions largely because the “network” operation of these integrated systems requires a unified, central control source.

Standard Offer Service: To provide an orderly transition, distribution companies are required to provide Standard Offer generation service to all customers who were receiving service as of March 1, 1998 and who have not chosen a competitive power supplier. This service is provided at a fixed price that increases annually until 2005. It is supplied to retail customers by the distribution company and is procured annually from competitive power suppliers through a periodic bidding process.

Default Service: This service is available to all customers who are not receiving competitive generation or standard offer service. Customers who move into a distribution company’s service territory after March 1, 1998 receive default service until they select a competitive supplier. Like standard offer rates, default service rates are regulated by the state but, over time, will be based on average market prices.

Mandated Rate Reductions: Another major provision of the Act guaranteed rate reductions. Beginning March 1, 1998, standard offer customers received at least a 10% discount off 1997 rates on their total bills. The discount increases to at least 15% on September 1, 1999.

Transition Costs Recovery: Many past utility investments in generation assets, which were deemed prudent and necessary at the time, may not be recoverable in the new competitive market and are, therefore, uneconomical. These investments are referred to as “stranded costs.” Utility stranded costs incurred before January 1, 1996 can be fully recovered through a transition charge on customers’ bills after all reasonable steps, including divestiture, are taken to mitigate stranded costs.

Divestiture of Generation Assets: In order to remove market power issues and minimize transition costs, vertically integrated companies were required to divest their non-nuclear generation assets in exchange for the right to recover stranded costs.

Public Benefit Programs: Special discounts for low-income customers are maintained and eligibility is expanded, and there is a new special 10% discount for customers engaged in farming. Charges to support energy efficiency programs that reduce consumer electricity demand continue. Programs to support renewable energy sources will be developed.

Consumer Protection and Education: Consumer protections are expanded to include the provision that low income customers who leave standard offer may return at any time; competitive supplier registration with the state; supplier electricity disclosure labels that include price data, contract terms, generation fuel, rates of emission created by those generation sources, and labor data; customer authorization to switch suppliers; and billing and termination protections. Educational materials, informational activities, and a toll-free telephone hotline were developed to assist customers in understanding and evaluating their rights and choices regarding supply options and related services.

Environmental Benefits: After the year 2003, greater environmental protections and a renewables generation portfolio requirement will be implemented.

II. PRICES AND PRICE DISPARITIES

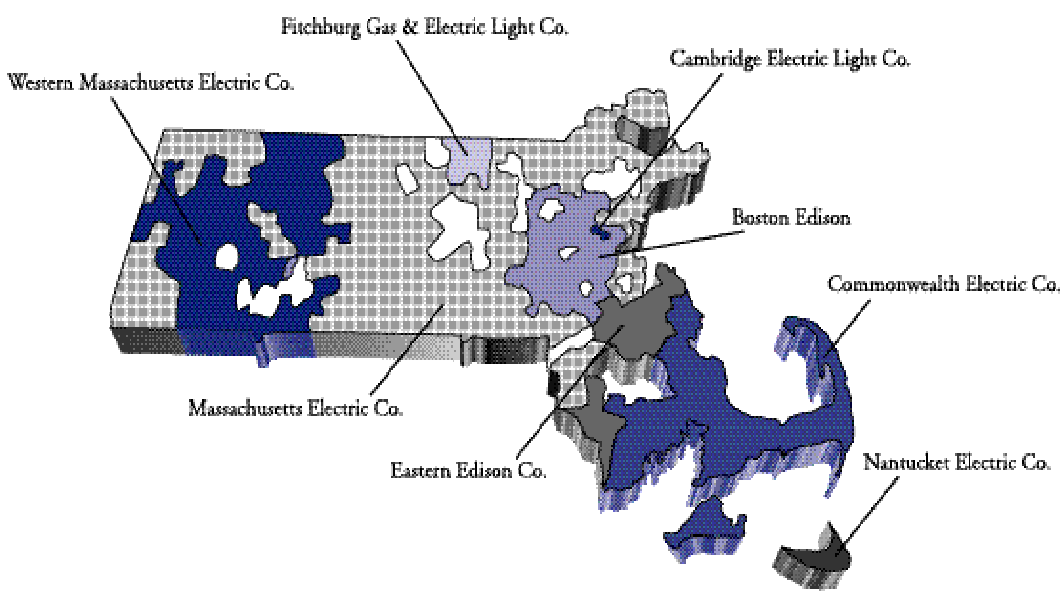
This section reviews the rate reductions required of the distribution companies. It also highlights and analyzes the disparities of the price components among the Massachusetts distribution companies.[3] In addition, there is a comparison of electricity prices in Massachusetts, New England and the U.S.

2.1 Massachusetts Electric Distribution Companies

Eight Investor-Owned Distribution Companies Supplied about 87% of the State's Electricity.

In Massachusetts, eight investor-owned distribution companies and forty municipal distribution companies provide electric service. Figure 2.1 presents a map of Massachusetts showing the location of each investor–owned distribution company service territory. Unshaded areas are municipal distribution company service territories.

Figure 2.1: Distribution Company Service Territories



Source: Department of Telecommunications and Energy

Investor-owned electric distribution companies supply about 87% of the state's electricity, serving 2.4 million customers and generate $4.0 billion in revenue. The remaining 13% is purchased or generated by publicly-owned municipal electric companies to serve their .3 million customers. Together with the municipal companies, the state's total electric industry receives about $4.6 billion in revenue each year. Table 2.1 provides 1998 statistics for the eight investor-owned distribution companies.

[3] "Rate" refers to a filed rate by the distribution companies that is given on a per energy unit basis. "Price" refers to a calculation of customers' payments that can then be examined on a bill. The rate times the volume consumed leads to the total amount paid.

Table 2.1: 1998 Statistics for Investor-Owned Distribution Companies

Distribution Company	Average No. of Consumers in 1998	Total Electric Revenue from Sales to Consumers ($ Millions)	Total Sales to Consumers in 1998 ($ Millions)	Average Overall Price in 1998 (cents per kWh)
Boston Edison	667,036	$1,408.2	13,416.5	10.5
Cambridge Electric	45,882	$108.9	1,340.1	8.1
Commonwealth Electric	327,033	$388.8	3,505.9	11.1
Eastern Edison	193,658	$248.1	2,707.9	9.2
Fitchburg Gas & Electric	28,936	$50.8	483.7	10.5
Massachusetts Electric	972,056	$1,468.9	16,590.9	8.9
Nantucket Electric	9,978	$12.7	99.8	12.7
Western Massachusetts Electric	196,323	$354.9	3,749.9	9.5
Total: Distribution Company	2,440,902	$4,041.3	41,895.1	9.6
Total: Municipal Company	336,656	$575.1	6,207.9	9.3
Total of Entire State	2,777,558	$4,616.4	48,103.0	9.6

Source: 1999 FERC Form 1, page 300-301, EIA-861 preliminary data (1998)

The Act mainly affects the investor-owned distribution companies and their customers because the state has regulatory control over these companies. The forty municipal electric companies currently operating in Massachusetts are exempt from key provisions in the Act since they are publicly-owned and operated.

However, the Act requires that municipal distribution companies that decide to compete for new customers outside their existing service territories, must open their own systems to competition. In addition, the Act requires municipal distribution companies that have not allowed their customers choice of supplier by March 1, 2003 to conduct studies on implications of offering choice, which could result in a referendum on the question if the municipal governing body so decides. Presently, municipal distribution company prices are, on average, 4% lower than the prices of the investor-owned distribution companies. Table 2.2 compares average investor-owned utility prices to municipal utility prices.

Table 2.2: Comparison of Distribution Company and Municipal Company Prices

	Residential	Commercial	Industrial	Overall
Average Distribution Company Price (cents per kWh)	10.8	9.3	8.1	9.6
Average Municipal Utility Price (cents per kWh)	9.5	10.4	8.6	9.3
Municipal Utility Price Difference	-12%	11%	7%	-4%

Source: Energy Information Administration, Form EIA-861 preliminary data (1998)

2.2 Price Disparity by Customer Class

The First Year of Restructuring Did Not Change Price Disparities.

A broad examination of 1997 and 1998 prices for residential, commercial, and industrial customers of the eight distribution companies shows that prices fell for all customer classes.

Presented in Table 2.3 are 1997 and 1998 prices. The primary cause for the drop in overall prices was the 10% mandatory rate reduction beginning March 1, 1998. (The mandatory rate reduction is examined in more detail below). A comparison of the overall price variance in 1997, the year prior to deregulation, to 1998 price variance shows that there are statistically insignificant changes. Based on these data, restructuring has not yet altered the degree of price disparity between distribution companies.

Table 2.3: 1997 and 1998 Price Levels for Massachusetts Distribution Companies[4]
(cents/kWh)

Distribution Company	Residential		Commercial		Industrial*		Overall	
	1997	1998	1997	1998	1997	1998	1997	1998
Boston Edison	13.2	12.0	11.0	10.0	10.1	9.2	11.6	10.5
Cambridge Electric	12.9	11.5	8.8	7.6	8.1	7.0	9.3	8.1
Commonwealth Electric	13.8	12.5	11.0	10.0	9.1	8.5	12.2	11.1
Eastern Edison	11.0	9.8	9.9	8.6	9.8	8.5	10.4	9.2
Fitchburg Gas & Electric	12.4	11.9	12.4	11.8	8.8	8.9	10.7	10.5
Massachusetts Electric	10.8	9.7	9.6	8.7	8.3	7.7	9.8	8.9
Nantucket Electric	13.2	12.3	14.6	13.2	18.9	18.3	13.8	12.7
Western Massachusetts Electric	11.7	10.8	10.0	9.3	8.1	7.7	10.1	9.5
Price Disparity	1.4	1.5	3.8	3.7	.7	.6	2.2	2.3

Source: Federal Energy Regulatory Commission Form 1
*Note: Calculation excludes Nantucket Electric

2.3 Impact of Mandated 10 Percent Rate Reduction by Customer Class

Customers Saved Almost $450 million in 1998.

Under the Act, the eight (investor-owned) distribution companies in Massachusetts were required to offer a 10% rate reduction on a customer's entire bill beginning March 1, 1998 to all customers of record as of that date. The discount applied to August 1997 rates. This resulted in approximately $450 million in savings in 1998 for distribution company customers, as shown in Table 2.4. The annual savings from the mandatory 10% rate cut were approximately $77 per residential customer, $756 per commercial customer, and $8,327 per industrial customer.

[4] 1997 and 1998 prices are for the entire year. The mandatory 10% rate reductions apply to a comparison of August 1997 to March 1998 rates.

Table 2.4: Savings from 10% Mandated Rate Reduction

	Residential	Commercial	Industrial	Other	All Customers
1998 Sales (billions of kWh)	13.991	20.012	7.603	0.289	41.895
Average Number of Customers (1998)	2,153,422	272,825	8,034	6,621	2,440,902
Average Revenue (cents) per kWh pre-3/1/98	11.9	10.3	8.8	20.3	10.7
Average Annual Expenditures pre-3/1/98 ($)	$773	$7,565	$83,279	$8,864	$1,837
Average Annual Savings per Customer ($)	$77	$756	$8,328	$886	$184
Estimated Total Savings in 1998 (millions of $)	$166	$206	$67	$6	$448

Sources: Energy Information Administration EIA Forms (1997), EIA Power Annual 1998, DOER

To illustrate that each distribution company met the 10% rate reduction, Table 2.5 employs a price comparison of three "typical" customers. March 1, 1998 prices are compared to a common reference point using August 1997 rates. In the table, January 1998 electricity bills on a cents per kilowatt-hour basis are compared to March 1998 bills since no distribution company, except for Western Massachusetts Electric, had any rate changes between August 1997 and January 1, 1998.

The analysis uses the standard offer generation service rate, since this rate applies to the majority of customers. The parameters represent average small, medium and large customers. For comparison, the profiles of the three customer classes analyzed in this section are:

> Residential - 600 kilowatt-hour (kWh) monthly energy usage, no space heating, and not low-income;
>
> Small commercial or industrial – 10,000 kWh monthly energy usage, 40 kilowatt (kW) monthly peak demand, and no additional discounts; and
>
> Large commercial or industrial – 1,260,000 kWh monthly energy usage, 2500 kW monthly peak demand, 50/50 peak/off-peak split, 1.0 power factor, and no additional discounts.

All the distribution companies, except for Nantucket Electric, had rate decreases of at least 10% for all three typical customers. Nantucket Electric is unique in that they also charge a "cable-facilities surcharge." However, if this surcharge is excluded, the rate structure becomes identical to that of Massachusetts Electric and meets the 10% requirement.

Though most of the companies exactly fulfilled the rate reduction, some distribution companies exceeded the 10% rate reduction during 1998. For example, Massachusetts Electric Company had a rate change as of September 1, 1998. According to DOER calculations, the rate change resulted in reductions greater than 18% for the last four months of 1998. It is likely that Massachusetts customers saved well in excess of the $450 million attributed to the 10% rate reduction alone.

The final row in Table 2.5 shows the variances for 1997 and 1998 prices.[5] A high variance indicates greater disparity among distribution company prices for that year. Thus, the table shows greater price disparity among the residential and small commercial or industrial customers as compared to the large industrial customer. In other words, prices across distribution companies are most similar for large customers. Price disparity can be due to a number of reasons, including the composition of the customer base for each distribution company, the market power of larger industrial customers, and the absence of market power of smaller customers.

DOER also examined whether price disparity among the distribution companies changed from the pre-restructuring reference date to March 1, 1998, the post-restructuring era. As shown by the F-Test value, for the residential customer, there is a 95% chance that disparity did not change due to restructuring.[6] The other two percentages are also quite high, indicating that restructuring had little or no impact on price disparity in 1998. Thus, the conclusions from this analysis correspond to those from Table 2.3.

Table 2.5: Illustration of Mandated Rate Reduction for Three Typical Customers

Distribution Company	Residential			Small Commercial or Industrial			Large Commercial or Indusrial		
	Jan'98	Mar'98	Change	Jan'98	Mar'98	Change	Jan'98	Mar'98	Change
Boston Edison	13.3	11.9	-10.0%	10.6	9.6	-10.0%	8.5	7.6	-10.0%
Cambridge Electric	12.4	10.6	-14.5%	11.3	9.6	-14.9%	8.2	6.9	-16.7%
Commonwealth Electric	14.0	12.6	-10.0%	11.6	10.5	-10.0%	9.4	8.5	-10.0%
Eastern Edison	11.5	10.3	-10.7%	11.0	9.5	-13.3%	9.0	7.8	-13.2%
Fitchburg Gas & Electric	12.7	11.4	-10.1%	12.0	10.8	-10.1%	8.8	7.9	-10.1%
Massachusetts Electric	11.0	9.8	-11.2%	11.6	10.3	-11.0%	8.5	7.4	-11.4%
Nantucket Electric	12.5	11.3	-9.9%	14.0	12.7	-9.1%	9.4	8.6	-10.0%
Western Massachusetts Electric	11.9	11.3	-10.0%	11.3	10.5	-10.0%	8.5	7.6	-10.0%
Variance	0.9	0.8	F-TEST 94.7%	1.1	1.1	F-TEST 93.4%	0.2	0.3	F-TEST 76.7%

Source: Distribution Companies, DOER

Note: Prices shown are rounded and thus may not correspond exactly to the percentage and variance calculations.

[5] Variances were calculated from the unweighted averages.

[6] The F-Test cell shows the probability that the variances for each of the reference dates (and thus disparity) do not differ to a statistically significant degree.

2.4 Unbundled Bill Components

The Department of Telecommunications and Energy (DTE) regulations, "Rules Governing the Restructuring of the Electric Industry," required each distribution company to submit a restructuring plan that detailed how they would comply with the Act and DTE regulations. Among other provisions, the DTE regulations called for the distribution companies to present customers with itemized or "unbundled" bills starting in March 1998. Each distribution company separately identified on the bill the charges collected from ratepayers for services including: customer and distribution, transmission, generation, transition, energy efficiency and renewable energy. The following provides a brief description of these components.

<u>Delivery Services</u>

These services will continue to be regulated by the DTE or FERC.

Customer and Distribution Charges: These two components cover the costs of distribution services. Distribution is the process by which electricity is provided to the customer over local low-voltage electricity lines. The customer charge is the monthly fixed rate that pertains to customer service, meter reading, billing, and payment functions. The distribution charge covers costs related to operating and maintaining the distribution lines and poles and for restoring service in the event of an outage.

Transition Charge: Transition charges are used to recover the costs of past utility investments related to generation service that cannot be recovered in the competitive market (known as stranded costs.) The transition charge is a temporary charge that is scheduled to decrease over time until stranded costs are fully recovered.

Transmission Charge: Transmission refers to the delivery of electricity from a power generator to the local distribution company over high-voltage power lines.

Energy Conservation Charge: This charge supports energy efficiency programs intended to reduce consumer electricity demand. For 1998, this charge was 0.330 cents per kilowatt-hour.

Renewable Energy Charge: This charge will be used to support the development of renewable technologies and the creation of a Massachusetts renewable industry. For 1998, this charge was 0.075 cents per kilowatt-hour.

<u>Supplier Services</u>

The Act mandates that three types of generation services are to be made available to end-users: standard offer, default, and competitive generation.

Standard Offer Service: Available to consumers who were distribution company customers on March 1, 1998, the standard offer charge is a transitional rate that is intended to provide an orderly migration of customers to the competitive market. On March 1, 1998, standard offer customers received a 10% discount from 1997 rates off their total bill. This rate is set by the DTE.

Default Service: Available to customers who are not receiving competitive generation or standard offer service, customers who move into a distribution company's service territory after March 1, 1998 receive default service until they select a competitive supplier. Like standard offer, this rate is set by the DTE. During 1998, it was set at the standard offer rate. In coming years, it will be based on market prices.

Competitive Generation Service: Provided by competitive suppliers licensed to sell electricity in the state, competitive generation service rates are not regulated by DTE. They are determined by market forces.

2.5 Price Disparity by Unbundled Bill Components

<u>Residential Customer</u>

Before showing unbundled price data, Figure 2.2 shows the overall disparity in terms of deviation from the weighted average. Because the eight distribution companies differ substantially from each other in terms of number of customers and amount of electricity supplied, the analysis uses an average weighted by kilowatt-hours. Calculating the weighted average for a residential customer is relatively straightforward because the distribution companies feature the same class definition for this customer type. Performing this calculation for non-residential customers becomes more involved due to differing rate class definitions and categorization.

Figure 2.2: Deviation from Weighted Average of 1998 Monthly Residential Bills, 600 kWh

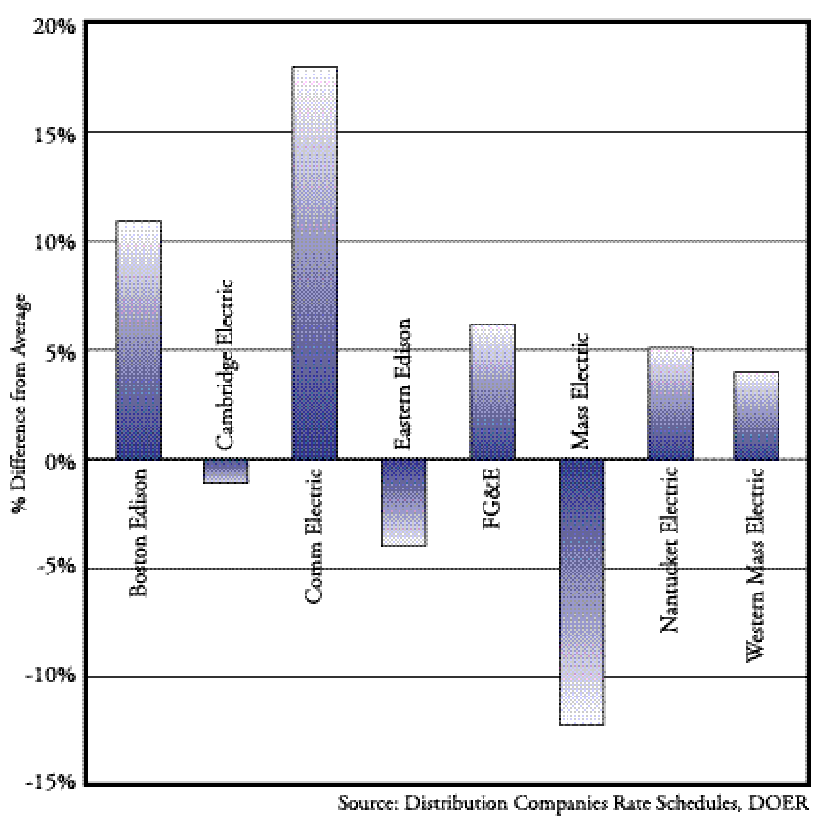


Figure 2.2 shows that residential bills for the same amount of electricity sometimes differ substantially among distribution companies. Commonwealth Electric customers paid about 18% more than the average statewide bill; Boston Edison is also substantially higher than the average. On the other hand, Massachusetts Electric customers paid over 10% less than the average. Unbundling of price components permits explanation of price disparity.

In order to examine price disparity further, unbundled price and bill calculations for the three customer types previously mentioned are outlined below. All calculations are average monthly prices and bills for the months of March to December 1998. An average was used in order to capture (1) any rate changes (in the form of decreases) that occurred after the March 1, 1998 mandated rate reductions and (2) any differential rates due to changes in seasons, which consist of summer months (June, July, August, and September) and winter months (October, November, December, January, February, March, April, and May).

Table 2.6 and Figure 2.3 show the unbundled prices for the residential customer described above. The data clearly show disparity among the distribution companies for the distribution, transmission, and transition cost components of the bill or price. The energy efficiency and renewables components (on a cent/kWh basis) do not vary among distribution companies or rate classes for 1998 rates, because they are mandated by the Act and are thus the same throughout this section of the report. The standard offer likewise is similar for all rate classes but there are variations due to rate changes during the year by some distribution companies. Due to the mandated rate reductions in March, 1998, all distribution companies featured the same standard offer of 2.8 cents per kWh but due to subsequent overall rate decreases, three of the distribution companies increased their standard offer while reducing (by a greater amount) their transition charges. Hence, there are slight differences among the standard offer for three of the distribution companies.

Table 2.6: Electricity Prices for 600 kWh Residential (R-1) Customers, (cents/kWh)

	Boston Edison	Cambridge Electric	Comm Electric	Eastern Edison	FG & E	Mass Electric	Nantucket Electric	Western Mass Electric
Standard Offer	3.080	2.800	2.800	2.800	2.800	2.960	2.960	2.800
Transition	3.174	2.730	4.080	3.040	2.820	2.187	2.187	3.174
Transmission	0.244	1.310	0.372	0.258	0.479	0.384	0.384	0.304
Distribution	4.972	3.356	4.985	3.779	4.875	3.740	5.343	4.448
Energy Efficiency	0.330	0.330	0.330	0.330	0.330	0.330	0.330	0.330
Renewable	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total	11.875	10.601	12.642	10.282	11.379	9.406	11.279	11.131

Source: Distribution Company Rate Schedules, DOER

Figure 2.3: Average Monthly Electric Prices for 600 kWh Residential (R-1) Customer By Distribution Company, March 1998 – December 1998

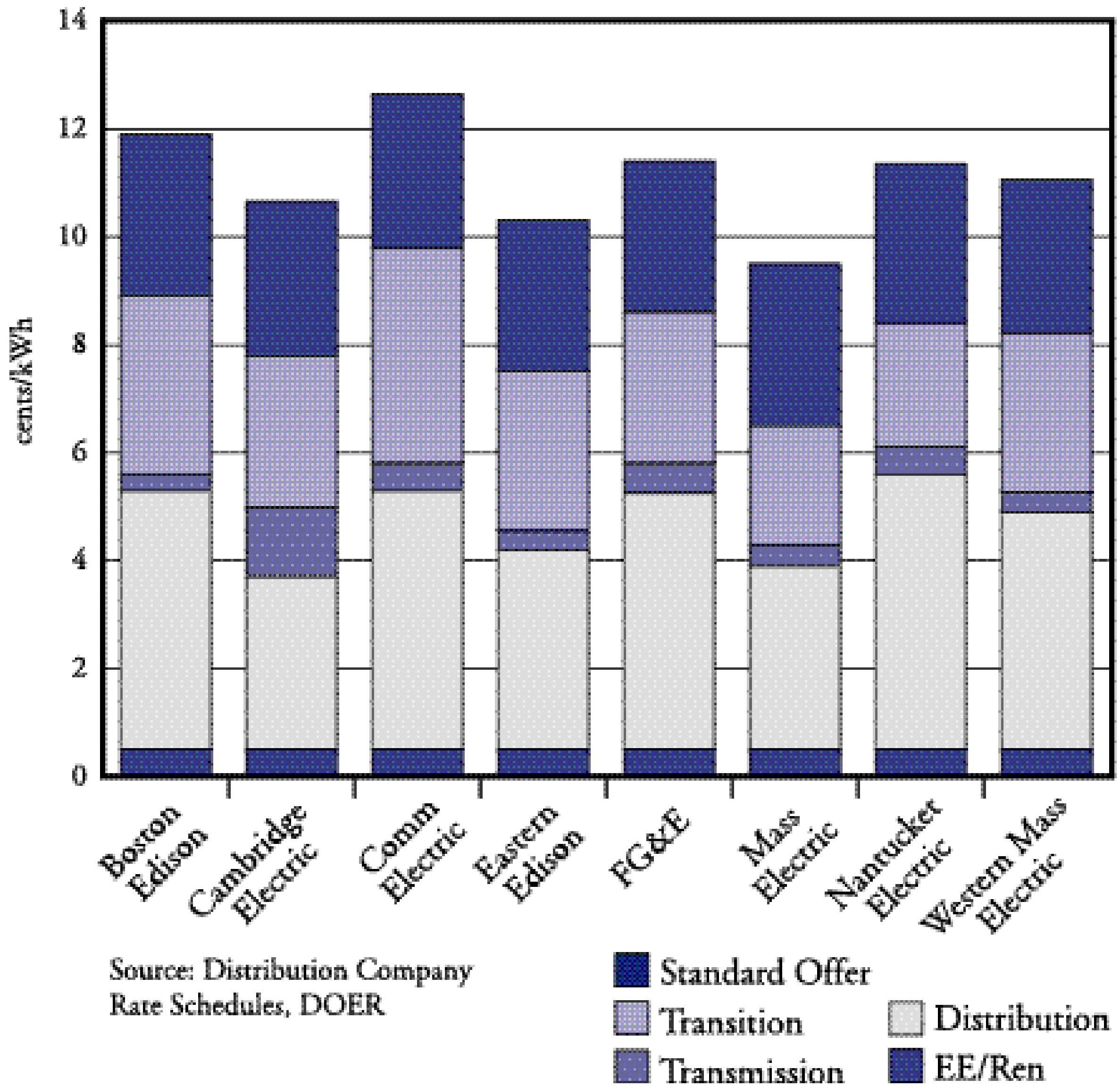


Figure 2.3 provides a graphical presentation of the data in Table 2.6. Distribution prices, which account for the largest part of the residential bill, range from a high of 5.343 cents/kWh for Nantucket Electric, which can be considered an outlier due to its additional cable facilities surcharge, to a low of 3.356 cent/kWh for Cambridge Electric. The figure clearly shows a grouping of four high distribution-price companies—Boston Edison, Commonwealth Electric, Fitchburg Gas & Electric, and Nantucket Electric—three low distribution-price companies—Cambridge Electric, Eastern Edison, and Massachusetts Electric—and Western Massachusetts Electric as a mid-to-high distribution-price company. The highest prices are about 30-40% greater than the lowest prices for the distribution component, thus partly explaining the disparity found in Figure 2.2.

One possible reason for distribution-price disparity is density, in terms of customers per mile of the distribution service territory. Sparsely populated service territories are expensive to maintain and service. In low-density systems, the investment per customer and the average customer-service response time are relatively high, thus making the cost to service each customer relatively high. On the other end of the spectrum, high-density systems are similarly expensive to serve. High-density systems, such as those containing large urban centers, will usually require underground lines, transformers and switches that are more expensive to install and maintain. Normal construction and maintenance is more difficult and costly in congested areas. In short, the cost of service for a distribution territory is high if the density is relatively low or high. The greatest cost (and thus price) advantage is for a moderately dense territory such as a well built-up suburb. Thus, density is a prime driver of distribution costs and prices.

A second reason is customer mix. Systems with a high proportion of distribution load that is comprised of large usage customers will be less costly to serve. Consider the amount of facilities, i.e., lines, transformers, service drops, and meters to serve 100 customers each with 5 kilowatts of load compared to facilities required to serve one customer with a 500-kilowatt load. Additionally, larger customers typically have higher utilization of their energy facilities or load factor. In other words, a 500-kilowatt customer will likely use far more energy (kilowatt-hours) than 100 customers of 5 kilowatts each will use. Therefore, the facilities needed to serve the kilowatt demand on a system and the amount of energy over which to recover the cost of those facilities will be dependent on the customer mix or average customer size in the service territory. Even at like densities, distribution system costs will vary significantly due to the mix of customers. Further explanation of the distribution-cost differences, though important, is beyond the scope of the current analysis and will be left for future reports.

Transmission charges represent a small percentage of a residential bill and feature more variation among the individual distribution companies. The charges range from 0.244 cents/kWh for Boston Edison to an extraordinarily high charge of 1.310 for Cambridge Electric. Again, further examination of the companies' underlying costs would be needed to explain the differences.

Transition charges represent the second highest residential bill component for a majority of the distribution companies. For two utilities, standard offer is higher because these utilities reduced their transition charges by selling off generation assets and subsequently increasing their standard offer. As transition costs decrease, standard offer charge can increase. A discussion of divestiture of generation and transition costs is included in Part III of the report. The data show that Commonwealth Electric has the highest transition prices per kWh and Nantucket Electric and Massachusetts Electric the lowest.

Using the above data, Table 2.7 shows the actual dollar amount paid by a typical residential customer using 600 kilowatt-hours for each of the distribution companies.

Table 2.7: Electricity Prices for 600 kWh Residential (R-1) Customers ($/month)

	Boston Edison	Cambridge Electric	Comm Electric	Eastern Edison	FG & E	Mass Electric	Nantucket Electric	Western Mass Electric
Standard Offer	18.48	16.80	16.80	16.80	16.80	17.76	17.76	16.80
Transition	19.04	16.38	24.48	18.24	16.92	13.12	13.12	18.49
Transmission	1.46	7.86	2.23	1.55	2.87	2.30	2.30	1.82
Distribution	29.83	20.14	29.91	22.68	29.25	20.82	32.06	26.69
DSM/Ren	2.43	2.43	2.43	2.43	2.43	2.43	2.43	2.43
Total	71.25	63.61	75.85	61.69	68.28	56.44	67.67	66.24

Source: Distribution Company Rate Schedules, DOER

Small Commercial or Industrial Customer

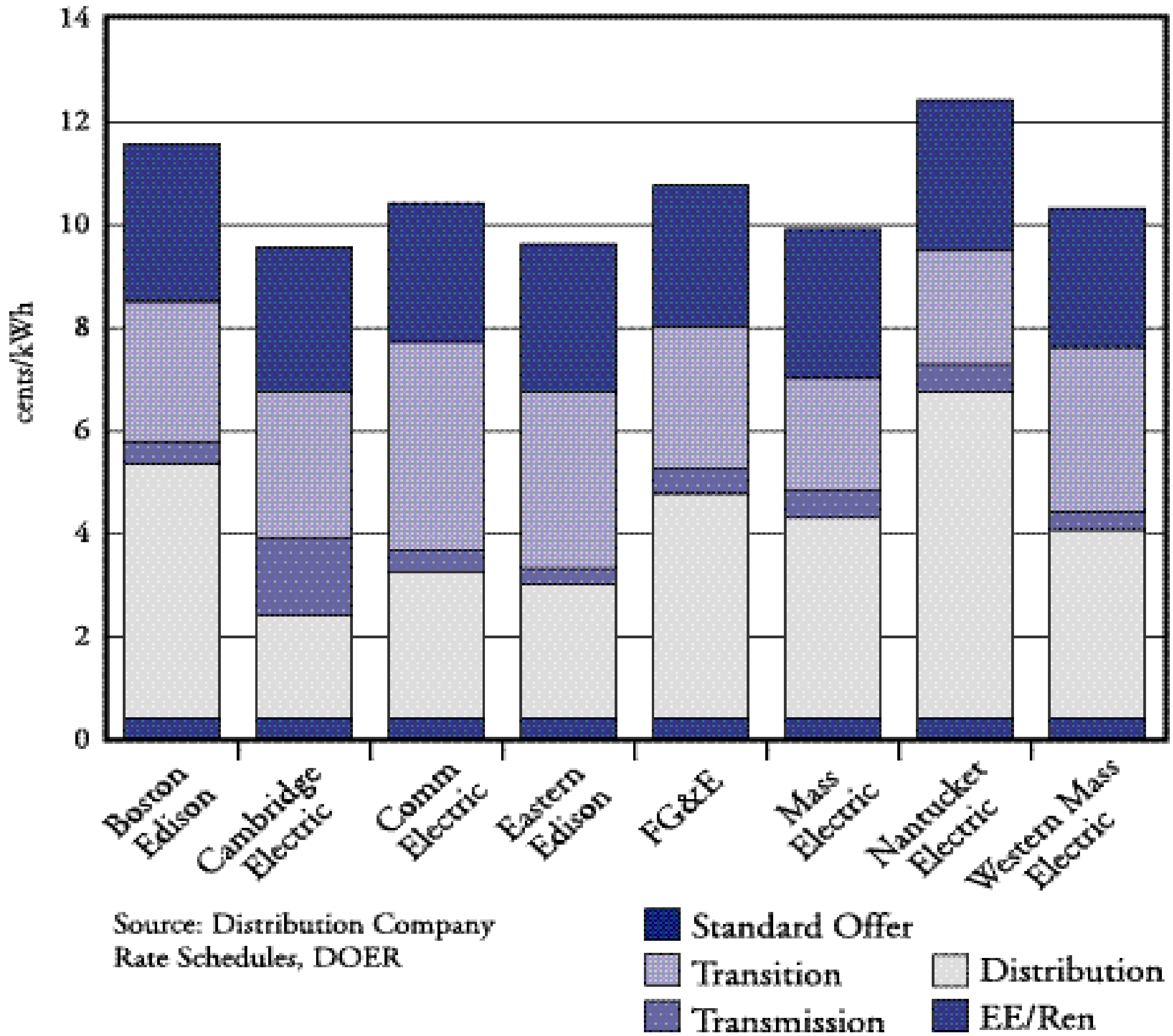
Table 2.8 and Figure 2.4 show unbundled prices for the small commercial or industrial customer that were described above. Figure 2.4 for the small commercial or industrial customer provides similar conclusions as Figure 2.3. Nantucket Electric remains an outlier, and distribution is the largest component of the electricity bill for a majority of distribution companies. However, a grouping of companies into high and low is not straightforward. In particular, Cambridge Electric features the lowest distribution rate for this customer type; Eastern Edison is also comparatively low. After Nantucket Electric, Boston Edison retains the highest distribution charges. Turning to transmission, a comparison of prices across the distribution companies shows that Cambridge Electric continues to be an extreme outlier for this price component. Finally, the transition data provide no additional insights to those obtained from the residential-price analysis.

Table 2.8: Electricity Prices for Small Commercial or Industrial Customer (cents/kWh)

	Boston Edison	Cambridge Electric	Comm Electric	Eastern Edison	FG & E	Mass Electric	Nantucket Electric	Western Mass Electric
Standard Offer	3.080	2.800	2.800	2.800	2.800	2.960	2.960	2.800
Transition	2.708	2.965	4.080	3.478	2.836	2.187	2.187	3.174
Transmission	0.379	1.460	0.378	0.258	0.471	0.475	0.475	0.381
Distribution	4.994	1.988	2.790	2.597	4.298	3.926	6.396	3.631
Energy Efficiency	0.330	0.330	0.330	0.330	0.330	0.330	0.330	0.330
Renewable	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total	11.566	9.618	10.453	9.538	10.810	9.953	12.423	10.391

Source: Distribution Company Rate Schedules, DOER

Figure 2.4: Average Monthly Electric Rates for 10,000 kWh Small Commercial or Industrial Customer by Distribution Company, March 1998-December 1998



Large Commercial or Industrial Customer

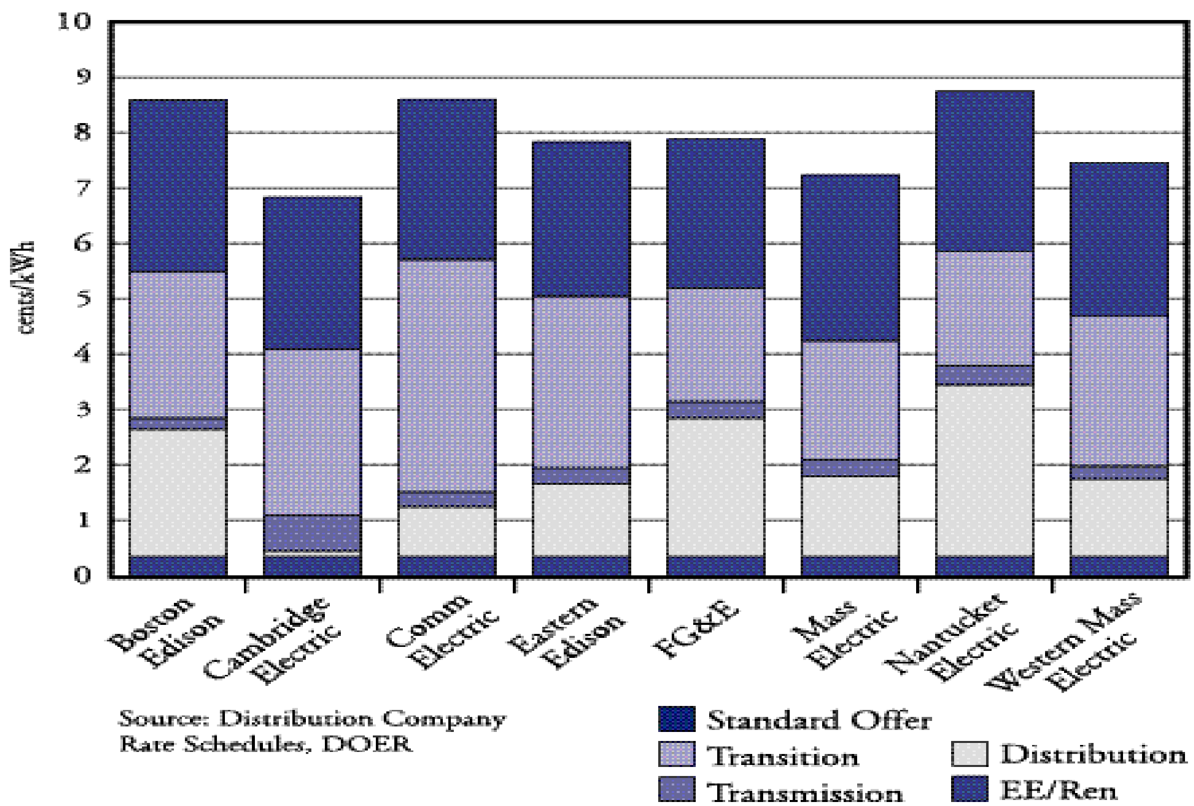
In order to compare distribution-company prices for a large customer, we examine the data found in Table 2.9 and Figure 2.5. The data show that for distribution prices, Nantucket Electric is the highest with Fitchburg Gas & Electric and Boston Edison comprising a high-price group above 2.2 cents/kWh. Cambridge Electric is an extreme outlier with almost a negligible distribution rate for this type of customer. Cambridge Electric remains the company with the highest transmission prices but the spread with the other companies is mitigated for this customer type. These two circumstances result in Cambridge Electric having the lowest overall price for this customer type. In terms of transition charges, Commonwealth Electric remains the highest; Fitchburg Electric features the lowest price for this customer type.

Table 2.9: Electricity Prices for Large Commercial or Industrial Customer (cents/kWh)

	Boston Edison	Cambridge Electric	Comm Electric	Eastern Edison	FG & E	Mass Electric	Nantucket Electric	Western Mass Electric
Standard Offer	3.080	2.800	2.800	2.800	2.800	2.960	2.960	2.800
Transition	2.601	2.969	4.110	3.110	1.859	2.055	2.055	2.782
Transmission	0.202	0.607	0.266	0.258	0.383	0.402	0.402	0.249
Distribution	2.256	0.083	0.906	1.283	2.494	1.317	2.952	1.309
Energy Efficiency	0.330	0.330	0.330	0.330	0.330	0.330	0.330	0.330
Renewable	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total	8.543	6.865	8.487	7.856	7.941	7.139	8.774	7.545

Source: Distribution Company Rate Schedules, DOER

Figure 2.5: Average Monthly Electric Prices for 1,260,000 kWh Large Commercial or Industrial Customer by Distribution Company, March 1998 - December 1998



2.6 Unbundled Price Disparity Among the Customer Types

As highlighted in the beginning of this disparity discussion, there clearly exists overall price disparity among different customer types. That is, residential rates are higher than small or large commercial/industrial customers, and large commercial or industrial customers have much lower prices than the other two customer types that were used for analysis. This disparity can be further examined by comparing the unbundled prices among the different customer types. Given that three of the price components—standard offer, efficiency, and renewables—do not change among the customer types, Table 2.10 only shows the distribution, transmission, and transition components. The total of the three, which is essentially the basis on which these companies will be competing as the transition period progresses, is also shown.

Table 2.10: Unbundled 1998 Rate Comparison For Three Customer Types (cents/kWh)

	Boston Edison	Cambridge Electric	Comm Electric	Eastern Edison	FG & E	Mass Electric	Nantucket Electric	Western Mass Electric
Distribution								
Residential	4.972	3.356	4.985	3.779	4.875	3.470	5.343	4.448
Small C or I	4.994	1.988	2.790	2.597	4.298	3.926	6.396	3.631
Large C or I	2.256	0.083	0.906	1.283	2.494	1.317	2.952	1.309
Transmission								
Residential	0.244	1.310	0.372	0.258	0.479	0.384	0.384	0.304
Small C or I	0.379	1.460	0.378	0.258	0.471	0.475	0.475	0.381
Large C or I	0.202	0.607	0.266	0.258	0.383	0.402	0.402	0.249
Transition								
Residential	3.174	2.730	4.080	3.040	2.820	2.187	2.187	3.082
Small C or I	2.708	2.965	4.080	3.478	2.836	2.187	2.187	3.174
Large C or I	2.601	2.969	4.110	3.110	1.859	2.055	2.055	2.782
Total								
Residential	8.390	7.396	9.437	7.077	8.174	6.041	7.914	7.834
Small C or I	8.081	6.413	7.248	6.333	7.605	6.588	9.058	7.186
Large C or I	5.059	3.659	5.282	4.651	4.736	3.774	5.409	4.340

Source: Tables 2.7, 2.8, 2.9

Clearly, price disparity exists among customer types within each distribution company. This can be seen by examining the “total” rows at the bottom of the table. After removing the standard offer, energy efficiency, and renewables components, which are essentially similar among the distribution companies, there is an even greater percentage difference among the customer types. For example, residential customers pay between 50 and 100% more per kilowatt-hour than large commercial/ industrial customers do. What is interesting is that different distribution companies price differentiate in varying ways. An examination of the distribution component shows that distribution prices are lowest for the large commercial or industrial customer. Among the distribution companies the highest priced distribution varies between the other two customer types, either residential or small commercial or industrial.

For transmission prices, the large commercial or industrial customer enjoys the lowest rate, and all but one company charges the most to the small commercial or industrial customer. One company, Eastern Edison, features the same transmission charge for all three customer types.

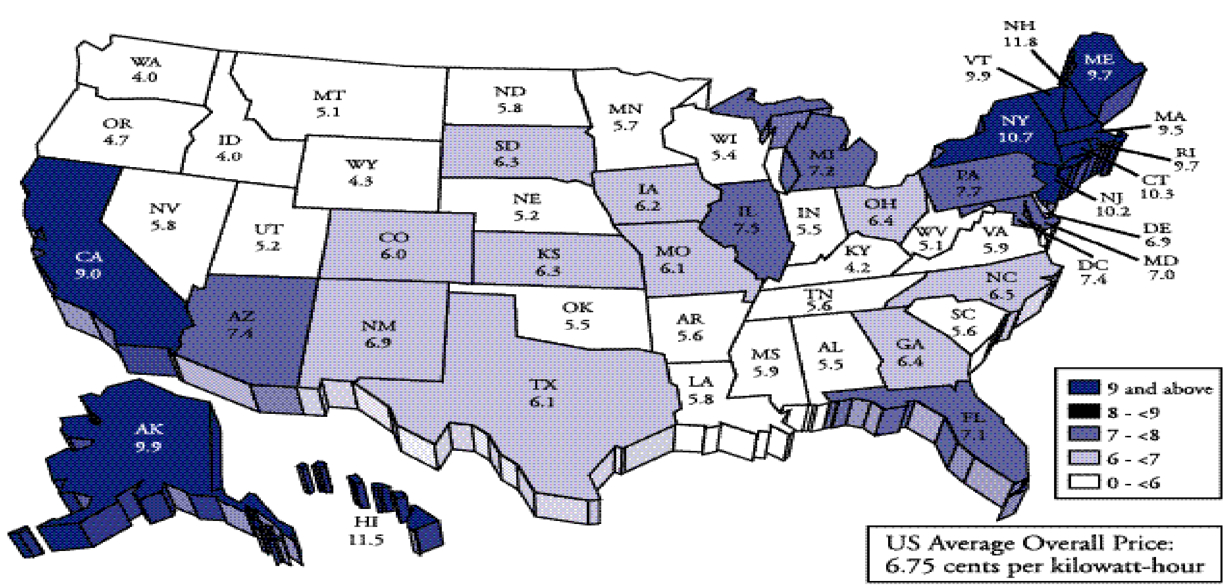
Finally, transition charges are quite similar across customer types for some distribution companies. Future analyses by DOER will attempt to explain these differences among customer types and attribute them to demand-side concerns, such as pricing to account for customers' market power (or lack thereof), or supply-side issues, such as higher costs of providing the service represented by the price component.

2.7 Electricity Prices: Massachusetts, New England and the Nation

In 1997, Massachusetts tied with New Jersey and Connecticut as having the 5th highest average electricity prices in the United States at 10.5 cents per kilowatt-hour. The national average was 6.85 cents per kilowatt-hour. At the end of 1998, Massachusetts, with average electricity prices at 9.5 cents per kilowatt-hour, dropped four places, largely due to the mandated rate cut, to become the 9th highest state.[7]

Figure 2.6 presents 1998 price data for each state. These prices are the weighted average of prices paid by all customers in each state. The average price for all states was 6.75 cents per kilowatt-hour, ranging from 4.0 cents per kilowatt-hour in Idaho to 11.8 cents per kilowatt-hour in New Hampshire, a variance of almost a factor of three. This dramatic disparity between states is the result of numerous regional differences, including fuel prices, climate, construction costs, labor costs, tax rates, customer mix, and the proximity of customers to the location of generation.

Figure 2.6: 1998 Average Overall Electricity Prices by State (cents/kWh)

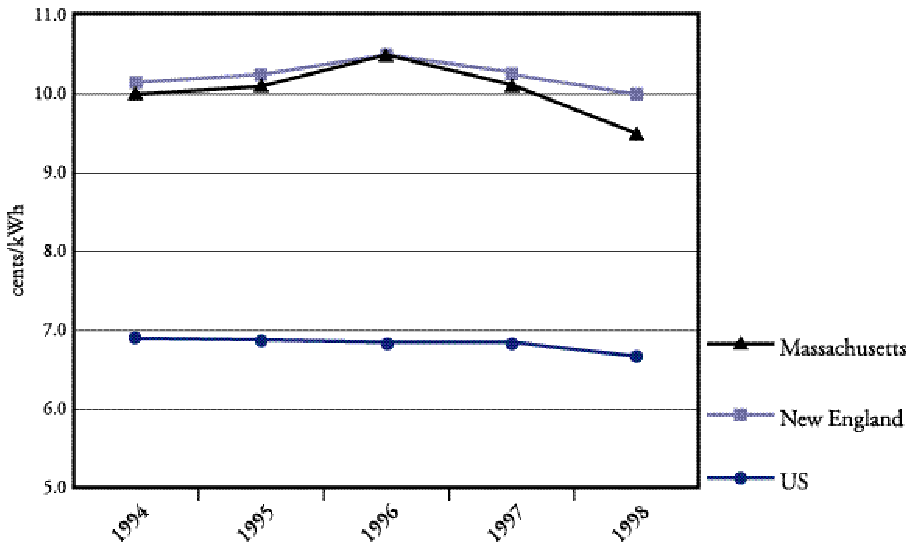


Source: Energy Information Administration "Average Revenue per kilowatthour for U.S. Electric Utilities by Sector, Census Division, and State, 1998" Electric Power Annual, 1998.

[7] Energy Information Administration, "Electric Power Monthly, March 1999," Table 55 for 1997 data and Energy Information Administration, "Electric Power Annual, April 1999." See Table A-15 for 1998 data.

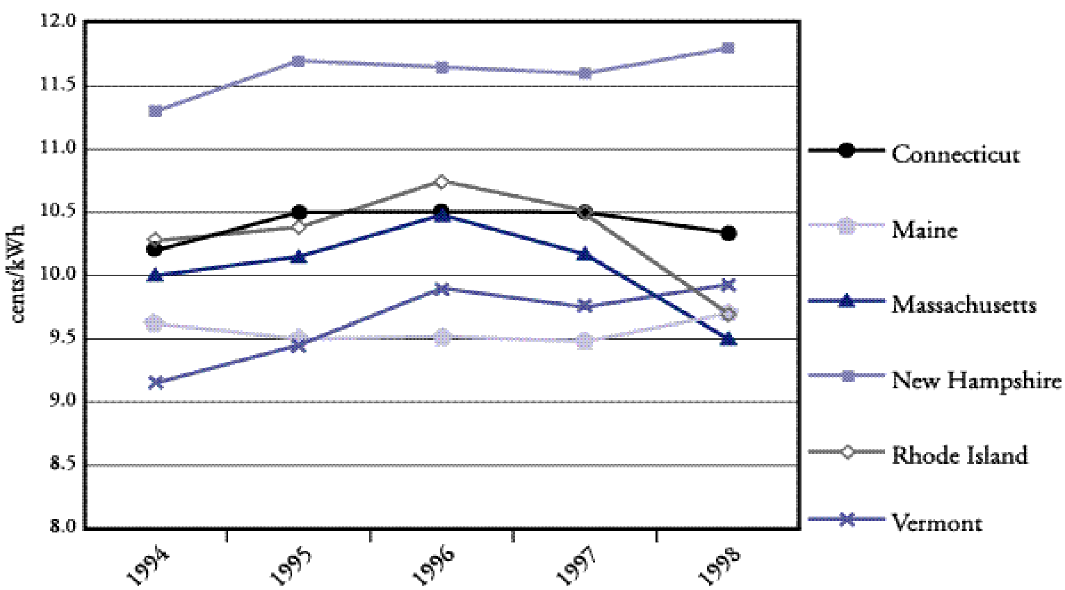
Figure 2.6 also clearly shows that New England states have among the highest electricity prices in the country. Figures 2.7 and 2.8 present historical pricing data for Massachusetts, New England, and the nation. As shown, Massachusetts and New England prices have historically been 45% to 50% higher than the national average. The impact of the Act's mandated rate reduction on Massachusetts prices in the first year of restructuring is shown. Rhode Island was the only other New England state that experienced an equivalent drop in electricity prices due primarily to their restructuring program's mandatory rate cut.

Figure 2.7: Historical Electricity Prices for all Customer Sectors: Massachusetts, New England States, and United States



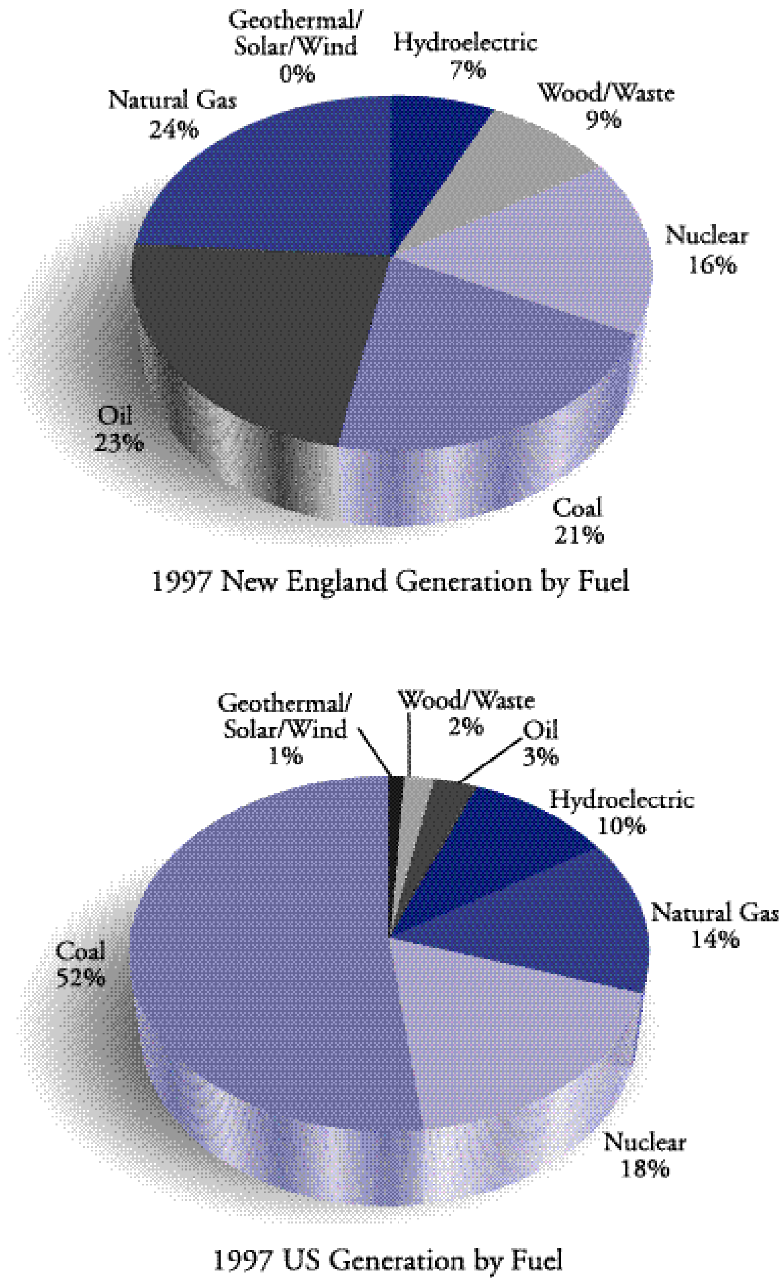
Source: Energy Information Administration "Average Revenue per kilowatthour for U.S. Electric Utilities by Sector, Census Division, and State, 1998" Electric Power Annual, 1998.

Figure 2.8: Historical Electricity Prices for All Customer Sectors: New England States



It is clear that even with the rate reductions experienced in 1998, Massachusetts electricity prices still remain among the highest in the nation. However, as transition costs decrease over time and competitive market forces strengthen, Massachusetts prices are expected to decrease even further. It is unlikely that Massachusetts' electricity prices will drop as low as the U.S. average. A number of regional factors specific to New England cannot be addressed by restructuring alone. For example, Figure 2.9 points out that New England's generation mix includes a higher percentage of expensive generating plants as compared to the national mix.

Figure 2.9: 1997 Generation by Fuel Type New England vs. the Nation



Source: (Non-Utilities) EIA Electric Power Annual 1997, Volume II, tables 54 & 58; (Utilities) EIA, Electric Power Annual, Volume II, tables 1 & 10

High cost plants include single-cycle oil/gas turbines, oil/gas steam plants, and oil/gas combined-cycle plants. Lower cost plants include coal-fired, hydro, and nuclear plants. Though more efficient natural gas-fired technologies are planned for New England, costs from these plants are still higher than plants in other regions. Regions of low cost generating capacity include the Midwest, which relies primarily on coal, and the Northwest, which has an ample supply of low-cost hydroelectric power. Furthermore, some regions of the country are served by federally owned electric utilities that, in addition to tax breaks, receive substantial federal subsidies.

Also, New England has limited inter-regional transmission capacity. In general, competition is expected to reduce the regional disparity in generation prices as low cost regions have the opportunity to sell power to higher cost regions. Absent transmission constraints, low cost power from the Midwest and Canada would greatly reduce the price of electricity in New England. Unfortunately, the capacity of New England's inter-regional transmission lines is limited, and new transmission lines are currently not planned.

In addition, labor costs in Massachusetts and New England are generally more expensive than the rest of the country. New England's electric fuel costs are typically higher than the national average primarily due to its distance from fuel source regions.

2.8 Prices by Customer Class: Massachusetts, New England and the Nation

The following discussion provides an analysis of price disparities that exist among the various customer classes in Massachusetts, New England, and the United States.

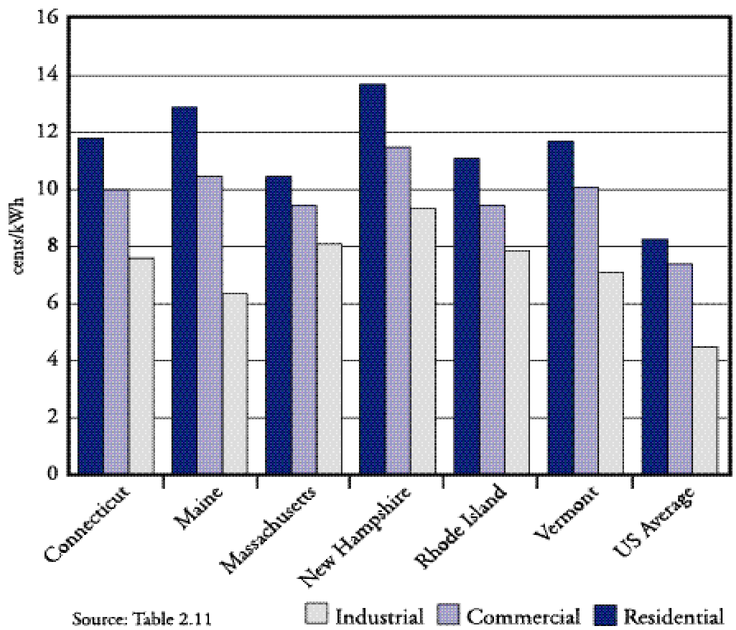
Table 2.11 and Figure 2.10 present data for each state and customer class in New England. Table 2.11 shows that Massachusetts' residential customers pay an average price of 10.5 cents per kWh, commercial customers pay less at 9.4 cents per kWh, and industrial customers pay the least at 8.1 cents per kwh. In 1998, compared to 1997, Massachusetts and Rhode Island experienced a decrease in overall electricity prices. Electricity prices increased in Maine and New Hampshire, while Connecticut had a small decrease. Vermont's overall prices remained the same.

Table 2.11: 1998 Electricity Prices by Customer Class
Percent Change from 1997 Prices

	All Sectors		Residential		Commercial		Indusrial	
	Price	% Change	Price	% Change	Price	% Change	Price	% Change
Connecticut	10.3	-1.90%	11.9	-1.65%	10.0	-2.91%	7.6	-2.56%
Maine	9.7	2.11%	12.9	1.57%	10.5	0.96%	6.4	0.00%
Massachusetts	9.5	-9.52%	10.5	-9.48%	9.4	-8.74%	8.1	-7.95%
New Hampshire	11.8	0.85%	13.7	0.00%	11.6	2.65%	9.3	2.20%
Rhode Island	9.7	-9.35%	11.1	-8.26%	9.4	-9.62%	7.8	-8.24%
Vermont	9.9	0.00%	11.7	1.74%	10.1	-1.94%	7.1	-4.05%
US Average	6.75	-1.46%	8.27	-1.90%	7.43	-2.11%	4.5	-0.66%

Sources: Energy Information Administration, "Electric Power Monthly, March 1999," Table 55. for data.
Energy Information Administration, "Electric Power Annual - 1998," Table A15 for 1998 data.

Figure 2.10: 1998 Electricity Prices by Sector, New England States, and US Average



The data show that there is a large difference in rates between customer classes within each state. For example, Massachusetts' prices show the smallest price spread across different customer classes. While its residential and commercial rates are the lowest in New England, Massachusetts industrial rates are the second highest in the region.

These prices reveal differences in rate structures among classes. There are three possible reasons for these differences.

First, the cost-of-service calculations are quite different for the customer types. For example, industrial customers, who are high volume and may be better able to manage their electricity demands, are less expensive to service than smaller residential customers.

Second, different customer classes have differing elasticities or abilities to "select" their distribution company through location or demand-related decisions. These decisions may be especially relevant in determining rate structures within the commercial and industrial sectors.

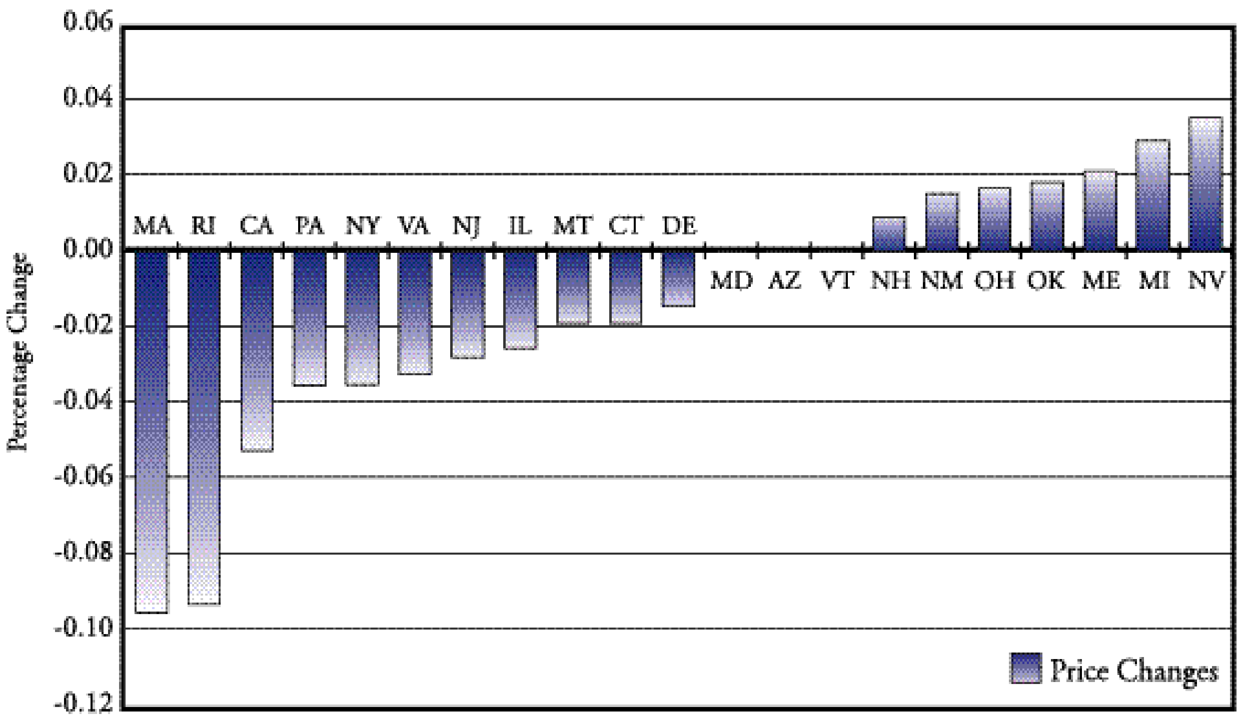
Third, because regulated electricity rates have been largely developed in the absence of market forces, factors other than economic ones have played a part in determining rates for each customer class. For example, the promotion of social goals, such as subsidized low- income and rural rates have long been (and continue to be) part of regulated rate structures and are sometimes handled differently by separate states.

As the market for competitive generation services develops, the differing costs of providing generation services (plus a return on investment) to the various customers will be reflected in differing retail market prices. The rates for transmission and distribution services will continue to be regulated.

2.9 Electricity Prices: Massachusetts, New England and Recently Deregulated States

Rhode Island became the first state to allow retail competition in its electricity market starting January 1, 1998. Massachusetts and California opened their markets to retail competition on March 1, and March 31, 1998, respectively. As of the end of 1998, 13 states had enacted legislation and 5 others issued final regulatory orders that deregulate their electric power industry and will eventually allow retail customers their choice of where to purchase electricity. [8] However, not all of the states in this group implemented restructuring in 1998. Some states - New York, Arizona, Pennsylvania - phased in restructuring for the different classes of customers. (Through April 1999, 19 states have legislation or final regulatory orders allowing retail competition.)[9]

In order to determine the effectiveness of Massachusetts' restructuring effort, it is useful to compare the price changes over time for some of the other restructured states. Figure 11 presents price data on a normalized basis for each of these states. As shown, it is clear that Massachusetts has experienced the greatest price reduction of the restructured states. DOER's future reports will continue to benchmark prices for restructured states in order to identify programs and opportunities that may be useful to Massachusetts.



Sources: Energy Information Administration, "Electric Power Monthly, March 1999," Table 55 for 1997 data.
Energy Information Administration, "Electric Power Annual - 1998," Table A15 for 1998 data.

[8] Energy Information Administration, "1998 Electric Power Annual," Volume I, p. 19.

[9] Ibid.

III. COMPETITIVE MARKET DEVELOPMENT

Throughout 1998 much of the infrastructure was put in place to support the development of a robust competitive market for retail generation services. Many market developments occurred despite the threat of the Act's repeal through a referendum on the November 1998 ballot. Actually, more than 70% of the Massachusetts voters chose to sustain the electric restructuring law, removing any doubt about its permanence. This section discusses the main market developments: (1) divestiture, (2) wholesale market developments, and (3) retail market developments.

3.1 Divestiture

Reduction of Stranded Costs by 29%.

A major cornerstone of the Act was the divestiture of generation assets to mitigate market power and provide for fair competition in the generation business. (Without divestiture, ratepayers would have had to continue to pay the full costs of all DTE approved generation assets.) Under the Act, distribution companies were allowed to recover prudently incurred costs after all reasonable steps, including divestiture of generation assets, are taken to mitigate the investments.

In order to receive approval to recover eligible transition (stranded) costs, distribution companies had to file a plan by March 1, 1998 with the DTE documenting the implementation of divestiture of their portfolio of all non-nuclear generation assets by August 1, 1999. The companies had to identify the costs, incurred prior to January 1, 1996, for which the company sought recovery. Among the costs were amounts for:

any unrecovered fixed costs for generation-related assets and obligations;

unrecovered reported book balances of existing generation-related regulatory assets;

previously incurred or known liabilities related to nuclear decommissioning and post-shut down obligations associated with nuclear power plants; and

existing purchase power contract commitments that exceed the competitive market price for power, or amounts necessary to liquidate such contracts.[10]

The initial statewide transition costs for Massachusetts, estimated by the distribution companies in their settlement or compliance filings, were about $9.7 billion in net present value terms.[11] The total transition charges in each filing was categorized as follows: fossil/hydro generation, nuclear generation, regulatory assets, and purchased power. Appendix B presents a breakdown of transition

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[10] "Rules Governing the Restructuring of the Electric Industry," DTE Order 96-100, Attachment A, p. A-7.

[11] The net present value transition charges were calculated in 1998 dollars and assume a discount rate of 8%. The initial transition charges estimated by each company do not include a Residual Value Credit (income from divestiture) for fossil/hydro or nuclear generating assets. The variable components of the transition charges are based on different initial market prices as estimated by each utility. Therefore, the companies' estimated total stranded costs may be high if the companies estimated a low market price for the units or contracts.

charges for each utility into these categories. The largest transition charge component is purchased power ($4.4 billion), followed by nuclear generation ($3.1 billion), fossil/hydro generation ($1.8 billion), and regulatory assets ($0.4 billion).

DOER analyzed the benefits of non-nuclear generation divestitures for companies that had completed or were in the process of completing asset sales as the end of October 1998.[12] Table 3.1 summarizes DOER's analysis of estimated benefits of non-nuclear divestitures.[13] On a statewide basis, the net present value benefits to customers are estimated to be almost $2.7 billion.

Table 3.1: Projected Benefits of Non-Nuclear Generation Divestitures and Net Stranded Costs for Electric Utilities in Massachusetts (Net present Value, $ Thousand)[14]

	Initial Transaction Charges Excluding Reg. Assets	Estimated Benefits of Non-nuclear Divestiture	Net Stranded Cost	Decrease as Result of Divestiture
Company Divestitures Completed by 10/98				
Boston Edison	$3,170,831	$464,051	$2,706,781	14.60%
Cambridge Electric	$190,221	$46,308	$143,913	24.30%
Comm Electric	$1,197,040	$265,654	$931,386	22.20%
MA Electric	$3,207,347	$1,766,752	$1,440,595	55.10%
Total - Completed	$7,765,439	$2,542,765	$5,222,674	32.70%
Divestitures Pending in 1998				
Eastern Edison	$574,077	$43,912	$530,165	7.60%
FG & E	$87,986	$13,026	$74,960	14.80%
Western Mass Electric	$851,375	$63,043	$788,332	7.40%
Total - Pending	$1,513,438	$119,981	$1,393,456	7.90%
Grand Total				
	$9,278,877	$2,662,746	$6,616,131	28.70%

Sources: Schedule 1 of company settlement filings/compliance filings, other company filings, and internal estimates.

[12] For purposes of the analysis, regulatory assets were excluded from both the initial transition charges and net stranded costs so total transition charges were approximately $9.3 billion.

[13] By April 1999, over 90% of the distribution companies' non-nuclear generation assets were sold to non-utility generators. In addition, Entergy in 1999 entered into an agreement with Boston Edison to purchase Pilgrim nuclear power plant for $80 million plus an additional $466 million to cover future decommissioning costs.

[14] A) MA Electric: includes benefits of $386.5 million from divestiture of purchased power contracts. B) Divestitures Pending: assumed an average purchase price of $367/kW for the remaining 10% of non-nuclear assets that have not been sold, based on the average purchase price received by other MA utilities. C) Eastern Edison: included actual proceeds from actual sale of some non-nuclear assets.

Initial statewide transition charges were expected to decrease as a result of non-nuclear generation divestitures by approximately 29%. On an individual basis, some distribution company transition charges actually were reduced more than others were. Massachusetts Electric Company's transition charges were projected to decrease about 55% as a result of divestiture.[15]

Transition Charges Decreased and Standard Offer Generation Prices Increased.

In March 1998, all distribution companies had identical standard offer retail generation rates of 2.8 cents per kilowatt-hour. In early 1997, the DOER, the Attorney General's Office and other stakeholders had negotiated settlement agreements with some of the distribution companies over the terms of those companies' restructuring plans, pending the passage of the Restructuring Act. One of the negotiated items was a standard offer generation rate of 2.8 cents per for kilowatt-hour in the first year of restructuring. (Another was the 10% rate cut.) This rate set a template for the other companies' standard offer retail generation rates. During the first year of restructuring, there was considerable evidence that this 2.8 cent price was below even the wholesale costs to supply generation services. For example, companies that did not purchase their supply as part of the sale of their generation assets (i.e., direct wholesale bid) paid substantially more for this power and accumulated "deferred losses" as a result. Therefore, competitive generation suppliers could not compete against the standard offer.

However, as a result of their divestiture of assets, three companies, Boston Edison, Massachusetts Electric, and Nantucket Electric, were able to use the proceeds to decrease their transition costs in 1998 and increase their standard offer generation rates.[16] No other companies increased their standard offer rate in 1998. (Nevertheless, the generation prices offered by these three companies to standard offer customers were still believed to be below the market price of electricity.) The simultaneous decrease in the transition charge and the increase in competitive generation portion of the bill meant that the overall price paid by standard offer customers did not increase. The higher generation price allowed marketers more opportunities to compete against the standard offer rate while having no negative affect on consumers who did not choose a competitive supplier.

Figure 3.1 represents the estimated trajectory, as developed by DOER, of the weighted average residential unbundled price components for all distribution companies through the seven-year transition period.[17] A number of conclusions can be seen by the graph. First, the graph shows the average post divestiture rate for all the distribution companies is lower and the standard offer is higher compared to March 1998 which represents pre-divestiture rates. (By 1999, all distribution companies had reduced their transition charge while increasing their standard offer charge.) Second, the

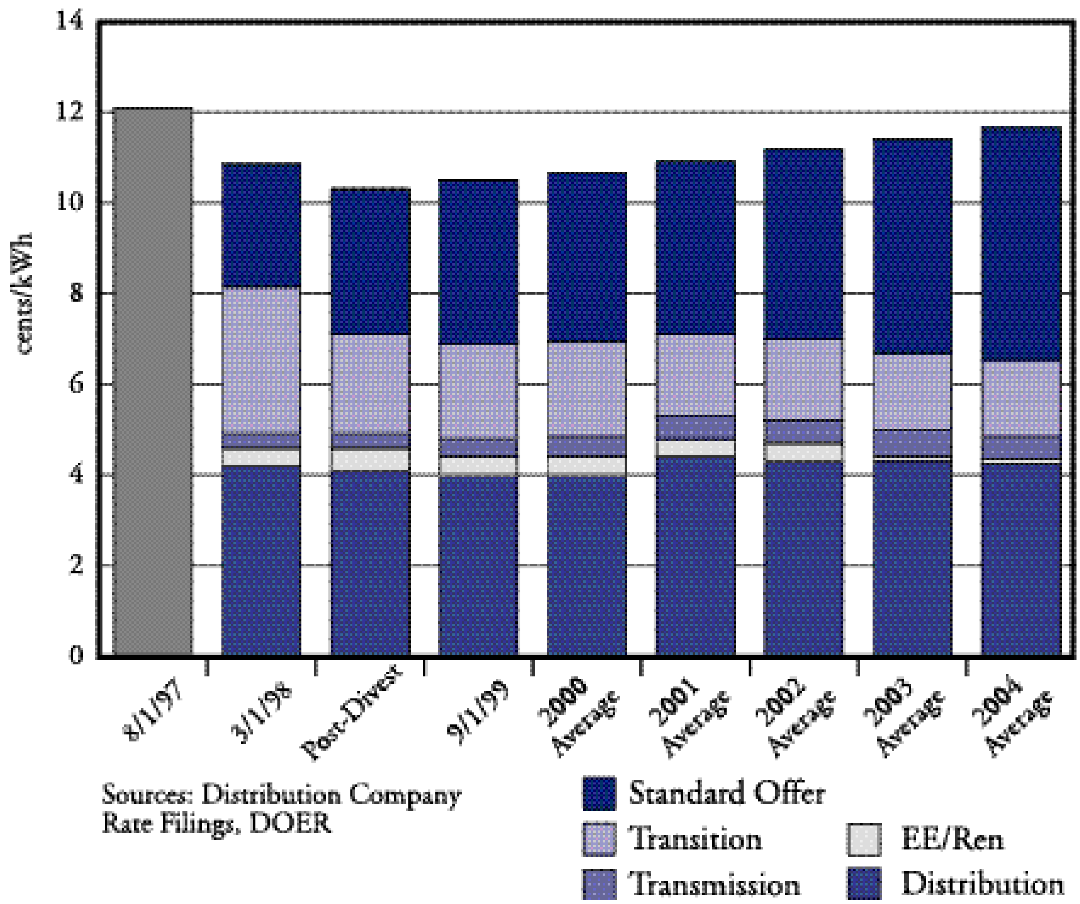
[15] Includes receipts from benefits of divestiture of company's purchased power contracts.

[16] In June 1998 Boston Edison raised their standard offer to 3.2 cents per kilowatt-hour. Massachusetts Electric and Nantucket Electric did the same in September 1998.

[17] Both the March 1, 1998 and Post-Divest-Date data points are actual rates on or after that date was reported by the utilities. The August 1, 1997 data point was calculated as the benchmark rate that would result in the 10% rate reduction as shown in the March 1, 1998 values. The September 1, 1999 values were obtained by applying the 15% rate reduction to the August 1997 values and adding an inflation factor. Finally, the remaining data points (for 2000 to 2004) were calculated by applying the inflation rate and calculating a weighted average of the monthly prices for each year.

standard offer rate steadily climbs over the transition period reaching its peak of 5.1 cents per kilowatt-hour in 2004. This increase should allow suppliers to compete against standard offer service. Third, as standard offer climbs to its highest level, transition charges steadily decrease. Fourth, assuming an inflation rate of 2.5%, the figure shows that 2004 rates are less than the pre-restructuring rates. Appendix C contains a version of the information in Figure 3.1 specific to each of the distribution companies.

Figure 3.1: Unbundled Price Trajectory – 600 kWh Residential Customer Weighted Average of Distribution Companies



New England Generation Market Share Changed.

As a result of divestiture of assets in Massachusetts and in other New England states, the ownership and market share of New England's generation market has changed. Table 3.2 presents the changes from 1997 to 1998 in utility and non-utility market share of generation capability. The measurement used for comparison is the company's existing NEPOOL capability as of January 1, 1998 and January 1, 1999, generation capacity determined by net megawatts, summer capability. Data are highlighted for the top eight utility companies and the Massachusetts Municipal Wholesale Electric Company (MMWEC) and the top eight non-utility companies.

As shown, in 1997 the top eight utilities had 91.8% market share. If MMWEC is included in that calculation, the market share rises to 94.6%. The non-utilities had 1.8%. By the end of 1998, those figures changed dramatically. The top eight utilities' share dropped to from 91.8% to 54.9% (57.7% with MMWEC included) and the non-utilities' share increased from 1.8% to 39.1%.

Table 3.2: Existing NEPOOL Capability; Generation Capacity by Company; Summer Net Capability (MW)

Rank	Company Name	1997 Summer Capability MW	1998 Summer Capability MW	% Change
	Utilities			
1	Northeast Utilities[26]	6157.91	7083.58	15.00%
2	NEES	4833.38	413.75	-91.4%
3	Boston Edison	3148.46	543.81	-82.7%
4	Central ME Power	1385.89	1366.28	-1.4%
5	United Illuminating	1346.71	1311.06	-2.7%
6	Comm. Energy	974.45	433.79	-55.5%
7	Eastern Utilities	916.63	552.70	-39.7%
8	Vermont Group	673.44	692.31	2.8%
9	MMWEC	596.38	633.18	6.2%
	Sub-total	*20,033.25*	*13,030.46*	
	Others	756.08	707.15	
	Total Utilities	*20,789.33*	*13,737.61*	
	Non-Utilities			
	PG&E (U.S. Gen)	0	4184.62	N/A
	Sithe	0	1968.77	N/A
	Southern	0	1237.04	N/A
	Select	0	484.19	N/A
	Duke Energy Trading	0	294.30	N/A
	TransCanada Power	0	234.49	N/A
	Milford Power Limited	149.00	149.00	0%
	Great Bay Power	140.98	140.93	0%
	Sub-total	*289.98*	*8693.34*	
	Others	86.51	132.95	
	Total non-utilities	*376.49*	*8826.29*	
	Total	21,165.82	22,563.90	
	Utilities & Non-Utilities Market Share	**% of Total**	**% of Total**	
	Top 8 utilities	91.8%	54.9%	
	Top 8 plus MMWEC	94.6%	57.7%	
	Non-utilities	1.8%	39.1%	

Sources: NEPOOL Forecast Report of Capacity, Energy, Loads, and Transmission, April 1, 1998 and April 1, 1999, section II.

The major influence in this market share change was divestiture. Although utilities such as Northeast Utilities and Central Maine Power ranked high in both years, they have also started to divest their generation. By the first quarter of 1999, approximately 11,000 MWs of capacity were sold or pending sales were announced. Table 3.3 presents the selling utility, the buyers of generation and plant capacity.

Table 3.3: Announced Sales of Electric Generating Assets, New England, as of 3/5/99

Electric Utility Owner	Units	Buyer	Cost ($ Million)	Capacity (MW)
CONNECTICUT				
United Illuminating	New Haven Harbor	Wisvest Corp. sub. of Wisconsin Energy	272	1056
MAINE				
Bangor Hydro	several hydro & fossil	PP&L Global, Inc.	89	89
Central ME Power	Four fossil & 27 hydro	FPL Group, Inc.	845	1185
MASSACHUSETTS				
Boston Edison	12 units	Sithe Energy, Inc.	657	2000
Boston Edison	Pilgrim nuclear plant	Entergy	80	670
Commonwealth Energy Eastern Utilities Assoc.	Four units of Com/Electric One unit of EUA	Southern Energy, Inc.	537	1260
Eastern Utilities Assoc.	Somerset Unit	Northern States Power	55	115
Western MA Electric	Several fossil & hydro	Con Edison of NY	47	290
MA , NH, RI				
New England Electric	15 hydro units & 3 fossil units plus power contracts	U.S. Gen New England, sub. of PG&E Corp	1590	4100
RHODE ISLAND				
Eastern Utilities Assoc.	Purchase power contracts & Newport Electric disel units	TransCanada Power Marketing; Wabash Power Equipment	N/A	170 16
TOTAL				
			4172	10,951

Source: Company News Releases, DOER

3.2 Wholesale Electricity Market Development

Delays in Implementation of Bid-Based Market System in 1998 Created Uncertainty for Wholesale Market Participants and, thus, Hampered Retail Competition.

In Order 888, the FERC required that “tight” power pools, such as the New England Power Pool (NEPOOL), file reformed pooling agreements by December 31, 1996. NEPOOL’s comprehensive filing provided for the creation of an Independent System Operator (ISO) to control the region’s transmission grid and generation operation, a regional transmission charge or tariff, and a revised NEPOOL governance structure. FERC conditionally accepted parts of NEPOOL’s filing, permitting implementation of the proposed tariff beginning March 1, 1997.

In July 1997 the administration and operation of the New England power grid was transferred from NEPOOL to ISO-New England. The ISO-New England's mission is to promote a healthy and competitive wholesale electricity marketplace while maintaining the highest standards of reliability, independence, and fairness.

Throughout 1998, ISO-New England, NEPOOL participants, and other interested parties worked together on rules and procedures to change the way the electricity was dispatched in New England. For more than 27 years, electricity was dispatched according to an economic-based calculation using the heat rate curve of a generating unit – how much fuel it takes a generator to produce electricity – and the price of fuel. Each generator was ranked from least expensive to most expensive to run according to these two variables. The economic ranking combined with a forecast predicting how much power would be needed the next day was used to determine which generators would be called into service.[18]

In the new proposed bid-based system, the ranking and selection of supplying power plants were to be changed. Instead of being ranked least to most expensive by cost-based fuel prices, the ranking of generating units would be based on market-based bids submitted by the owners of the generating plants.[19] (Appendix D describes in greater detail the market based bid system.) It is anticipated that the bulk of electricity transaction will occur through bilateral contracts between generation buyers and sellers. Residual energy needs can be bought and sold through the New England Power Exchange (PX) which is administered by the ISO. The integrated power exchange will provide additional market efficiency and liquidity to the wholesale electricity marketplace.[20]
Delays in opening of the new wholesale markets in 1998 made competitive acquisition of electricity and capacity difficult for some suppliers. The delay left in place the old system of wholesale electricity and capacity transactions only through bilateral contracts between buyer and seller. The introduction of the new markets for the buying and selling of wholesale electricity products allows buyers the option to buy all or part of their electricity needs from a "spot market" consisting of competitively bid prices from generators, as well as to purchase historical bilateral contract method. The development of a robust wholesale market is seen as key to a competitive retail environment.

[18] ISO New England, "1998 Annual Report," p. 14.
[19] Ibid.
[20] In February 1998, ISO-NE officials announced the fourth quarter of 1998 as a target for the startup for the region's competitive wholesale electricity markets. By June 1998, the ISO specifically announced December 1, 1998 as the target date, contingent upon timely finalization of market rules and a ruling by FERC on the acceptability of the market based rates. Finally, in December 1998, FERC gave conditional approval to NEPOOL's proposed market rules and request to transact at market-based rates. However, in November 1998 the ISO and market participants conducted a "Mock Market" test of the internet-based bidding and settlement systems and found that improvements to these system were needed. As a result, bid-based markets did not open in 1998, but were delayed until May 1999.

New Types of Wholesale Competitive Entities Entered the Market.

Prior to FERC's restructuring of the wholesale markets, the NEPOOL members consisted mostly of vertically integrated electric utilities, municipal utilities and transmission providers. The evolving competitive markets in Massachusetts and New England have spurred the formation of new types of wholesale market participants. By December 1998, NEPOOL had more than 110 members, referred to as participants, that included investor owned utility systems, municipal and consumer-owned systems, joint marketing agencies; power marketers, load aggregators, independent power producers, generation owners, and transmission and distribution companies. There are other entities, such as power brokers and buyer agents, who are creating deals at the wholesale and retail levels by matching prospective buyers with competitive suppliers. These entities are also active in forming large aggregations of consumers, thereby creating attractive bulk power sales opportunities for competitive suppliers. Appendix E lists the NEPOOL participants.

Over 30,000 Megawatts of New Power Plants Proposed.

In 1998, developers announced plans to build over 30,000 MWs of new generation capacity in New England. This compares to New England's existing capacity of approximately 25,000 MWs. While not all proposals will come to fruition, the increased competition from these new plants will force some of the existing, less efficient plants into retirement and will make the withdrawal of supply to increase bid price less likely. Additionally, the almost exclusive use of natural gas and other low emission fuels in these proposed plants will reduce air pollution and provide customers with cleaner generation choices. As these new and more efficient plants are built, competition will serve to drive prices downward. Appendix F lists the proposed plants.

3.3 Competitive Retail Market Developments in Massachusetts

About 22 Competitive Service Providers Licensed.

In 1998, the DTE finalized the procedures and rules for registering competitive suppliers and brokers and licensed 22 competitive service providers. Competitive suppliers sell electricity and related services to retail customers, with the exceptions of distribution companies that sell standard offer or default service and municipal light plants acting as a distribution company. Brokers, including but not limited to Aggregators[21], facilitate or otherwise arrange for the purchase and sale of electricity and related services to retail customers, but do not sell electricity. Appendix G lists the licensed providers as of June 1999.

Competitive Retail Markets Developed Slowly in 1998.

While many competitive service providers were licensed, suppliers found it very difficult to offer prices at or below the standard offer service price offered by the distribution companies since the

[21] An Aggregator groups together electricity customers for retail sale purposes, except for public entities, quasi-public entities or authorities, or subsidiary organizations thereof, established pursuant to the laws of the Commonwealth.

opening of the competitive market on March 1, 1998. The low standard offer price in conjunction with the costs (advertising, customer service, etc.) associated with marketing to individual customers and delays in restructuring the wholesale market, led to slow competitive retail market growth in 1998. As a result, few suppliers were able to sell power competitively to small customers. There were a few notable contracts signed between large customers and suppliers. For example, in December 1998, Texas Instruments signed an agreement to purchase electricity from Alternate Power Source, Inc. (APS) and TransCanada Power Marketing (TCPM) to provide electricity capacity and energy to Texas Instruments' manufacturing facilities in Attleboro, MA. Under the deal brokered by APS, TCPM provided the wholesale electricity requirements and APS is the retail provider.

However, the biggest moves to the competitive market occurred at the end of 1998 and beginning of 1999 when different aggregating entities grouped larger customers to buy electricity in bulk and concluded purchase agreements with competitive power suppliers. (Some of these aggregation entities are highlighted below.) Table 3.4 shows the composition of the distribution companies' customer base as of the first quarter of 1999. The data are kilowatt-hours for standard offer, default and competitive generation service for the first quarter of 1999. Competitive suppliers accounted for 1.3% of distribution company retail electricity sales. Most of this 1.3% is located in Massachusetts Electric Company's service territory. Figure 3.2 shows these data.

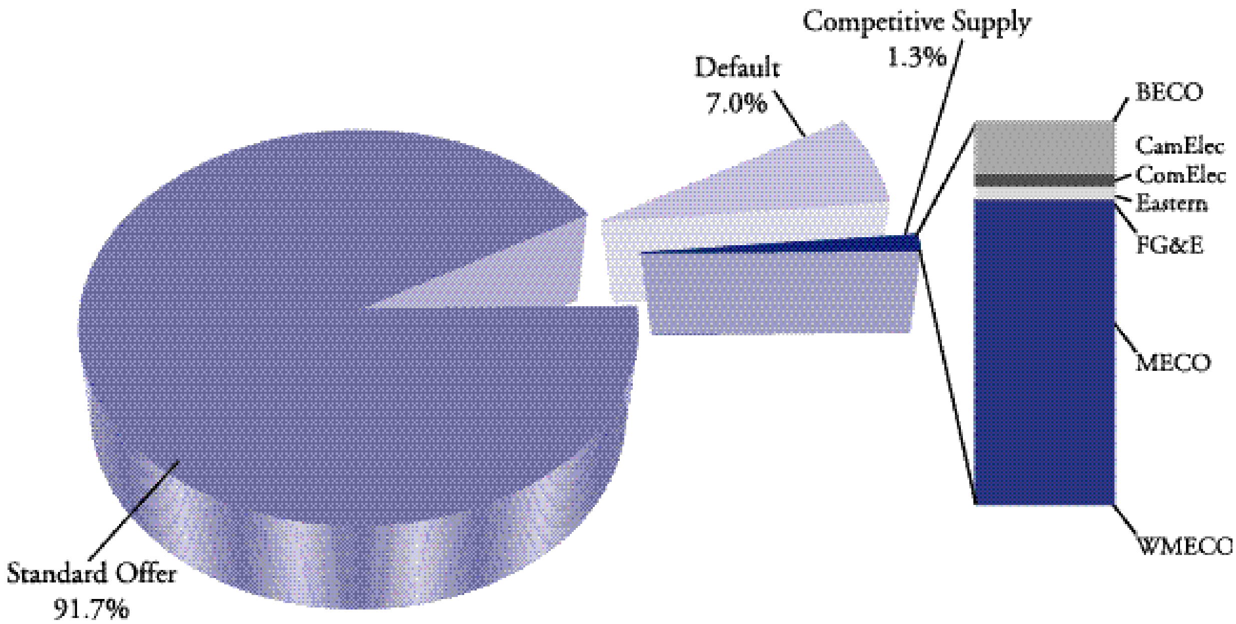
Table 3.4: Composition of Distribution Company Sales (kWh)–First Quarter 1999

	KWh	% of Total
Standard Offer	10,066,496,077	91.71%
Default Service	768,139,653	7.00%
Competitive Supply	142,357,205	1.30%
-- BECO	19,702,712	0.18%
-- CamElec	2451	*0.00%
-- ComElec	4,184,849	0.04%
-- Eastern	4,401,048	0.04%
-- FG&E	179,529	*0.00%
-- MECO	113,808,627	1.04%
-- Nantucket	0	0.00%
-- WMECO	77,989	*0.00%

Source: DOER

*Due to rounding, actual percentages are not shown.

Figure 3.2: Composition of Distribution Company Sales (kWh): First Quarter 1999



Source: DOER

Table 3.5 shows the customer composition data by broad customer types and includes number of customers in addition to kilowatt-hour sales. An examination of the competitive customers and competitive sales columns shows that competitive suppliers were heavily focused on large industrial and commercial customers. Over 98% of kWh competitive sales were to commercial and industrial customers and over 76% of competitive customers were commercial and industrial. Moreover, the average sale to a competitive customer was over 49,000 kWh per quarter. This focus on larger customers is not surprising because of the higher marketing costs associated with acquiring and serving individual residential and small commercial/industrial accounts.

Table 3.5: Distribution Customer Composition by Customer Type First Quarter 1999

	Standard Offer Customers	Standard Offer Sales (KWh)	Default Customers	Default Sales (KWh)	Competitive Customers	Competitive Sales (KWh)	Total Sales (KWh)	Total Customers
Residential	1,785,733	3,558,886,942	271,341	385,246,144	360	1,653,114	3,945,786,200	2,058,754
Low Income	122,862	199,887,243	2,279	3,770,035	0	0	203,657,278	125,167
Commercial	237,494	3,935,462,065	30,064	287,236,288	2,400	33,755,987	4,256,376,351	269,988
Industrial	5,308	2,364,517,883	391	91,709,842	144	106,948,104	2,563,175,829	5,855
Farms	1,229	7,741,944	38	177,344	0	0	7,919,286	1,267
Total	2,152,626	10,066,496,077	304,113	768,139,653	2,904	142,357,205	10,976,914,944	2,461,031

Source: DOER

Competitive Suppliers Focused on Large Commercial and Industrial Customers.

<u>Aggregation</u>

Major aggregation activity in Massachusetts at the end of 1998 and the first quarter of 1999 centered on the following groups:

The Massachusetts Health and Education Facilities Authority (HEFA): In 1996, HEFA formed PowerOptions, its energy buying program, to enable its non-profit members such as hospitals, colleges, universities, human service agencies and cultural institutions to save money through group purchase of electricity. In 1998, after a competitive process, HEFA signed with PECO Energy for electricity supplies. By the first quarter of 1999, about 280 members had signed up for electricity supplies.

The Massachusetts High Technology Council (MHTC): The MHTC is a group of high-tech companies in Massachusetts with over 200 members that represents approximately 1.2 million megawatt-hours annually. The group signed a multi-year contract with PG&E Services in September 1998. The agreement followed a successful pilot program by Massachusetts Electric and saved the MHTC over $3.8 million over the course of the program.

Mass. Municipal Association (MMA): MMA is a non-profit organization that provides advocacy, research and other services to Massachusetts cities and towns. MunEnergy is MMA's-sponsored energy aggregation program. MMA contracted with National Energy Choice (NEC), a licensed broker and competitive supplier to assist them with their power purchases for municipal buildings. Select Energy was chosen as the power supplier. In 1998, over 70 municipalities and eligible entities enrolled in the program.[22]

Massachusetts Chambers of Commerce: On behalf of their members, several Chambers of Commerce in 1998 began the process of forming purchasing groups and issuing Request for Proposals (RFPs) to potential suppliers. By the first quarter of 1999, Chambers including the Massachusetts Chamber Collaborative, North Central Massachusetts Chambers of Commerce, and the Greater Springfield Chamber[23] had selected suppliers.

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[22] MMA conducted a second round for enrollment and as of May 1999 has signed up about 50 eligible participants for a total of 120 participants. A third enrollment round will be offered in September 1999.

[23] Massachusetts Chamber Collaborative participants – South Shore Chamber of Commerce, Alliance for Amesbury, Cape Cod Regional Chamber of Commerce, Fall River Chamber of Commerce, Metro West Chamber of Commerce, Neponset Valley Chamber of Commerce, New Bedford Chamber of Commerce, Plymouth Area Chamber of Commerce, United Area of Commerce (Franklin).

North Central Massachusetts participants – North Central MA Chamber of Commerce, Wachusett Chamber of Commerce, Athol-Orange Chamber of Commerce.

Greater Springfield Chamber of Commerce includes Springfield, West Springfield, Agawam, Ludlow, East Longmeadow, Longmeadow, Hamden and Wilbraham.

Municipal Aggregation

The Act gives a municipal government special rights to aggregate. A municipality or group of municipalities combines interested electricity consumers (residential, commercial, industrial and municipal load) within its municipal boundaries to facilitate or otherwise arrange the purchase and sale of electricity.

In 1998, several cities and towns made progress toward becoming municipal aggregators. One group in particular, The Cape Light Compact (The Compact) made substantial progress. The Compact is an organization of municipalities located in Cape Cod and Martha's Vineyard representing 20 towns and in excess of 180,000 potential customers. Through its Community Choice program, the Compact sought a supplier for its power supply of up to 1.665 million megawatt-hours of energy. Although the Compact did not receive any acceptable bids in 1998, the Compact, during the first part of 1999 re-released the Request for Proposals (RFP) and announced that it was reviewing bids from four power suppliers.

In December 1998, the Town of Lexington issued an RFP for power supply for its aggregated customers - over 11,000 customers. In addition to power supply, bidders were asked to submit proposals for additional value added services, including retail natural gas supply, conservation or home management services. Lexington received one proposal but it did not match the town's requirements.

New Products and Services Are Being Developed.

Competitive suppliers and distribution company affiliates have developed a number of new products and services. There are two main groups of products emerging. The first group contains energy-related products, including metering services and energy efficiency services. The second group contains products that are suited to companies in the "wires" business. These include cable television, Internet, and other technology-related products. Companies active in the Massachusetts power market are developing both types of products.[24]

Mergers and Acquisitions Were Proposed.

Restructuring set off a wave of merger activity in 1998 and the first quarter of 1999. Activity included mergers between electric distribution companies as well as between electricity and gas distribution companies. This activity is a sign that distribution companies are re-inventing themselves as "wires and pipes" companies, focusing on building a new model for competing in a restructured world. Mergers allow companies to expand their customer base and their portfolio of products, while presumably realizing the cost benefits of increased economies of scale. Key mergers in 1998 include:

BECo/COM Energy: The combined holding company puts Boston Edison, Commonwealth Electric, Cambridge Electric, Commonwealth Gas and unregulated affiliates of both companies under one roof, creating the largest distribution company in Massachusetts. Together, the companies will serve

[24] DOER survey of competitive suppliers, power brokers and power marketers licensed in MA.

1.3 million customers with the goal of expanding the customer base to over 2 million.

NEES/National Grid Group plc: According to National Grid, the acquisition "provides the right point of entry into the U.S. for National Grid, given New England's favorable economic climate and its advanced state of regulatory evolution toward performance-based regulation."[25] It is likely that National Grid plans to seek additional expansion opportunities.

New England Electric System (NEES)/Eastern Utilities Associates: Announced in February 1999, the merger creates a combined base of 1.6 million customers in Rhode Island, Massachusetts and New Hampshire. The companies estimate that the merger will create $25 million a year in savings, primarily due to cutting duplicate administrative costs.

A Class Action Law Suit, "The Shea Case" Was Filed.

The Act requires distribution companies to include in their rates a mandatory charge on the retail sale of each kilowatt-hour of electricity consumed by ratepayers to fund cost-effective energy efficiency activities. Total energy efficiency funding collected in 1998 under the Act was about $137 million. The companies also collect a separate charge for a renewable energy trust fund to be administered by the Massachusetts Technology Park Corporation (MTPC). Depending on electricity sales, approximately $200 million will be collected for renewable energy activities through this charge over the first five years and more than $20 million per year after 2002.

In March 1998, a group of retail customers of Massachusetts electric distribution companies filed a class action suit, William E. Shea, et al, v. Boston Edison, et al., (the Shea Case), seeking a declaratory judgment at the Supreme Judicial Court (SJC) against their distribution companies, the Department of Telecommunication and Energy (DTE), the DOER and the MTPC. The complaint alleged that the Restructuring Act's requirement that distribution companies include in their rates mandatory charges for energy efficiency and renewable energy fund activities was unconstitutional under the Massachusetts Constitution and the Equal Protection clause of the Fourteenth Amendment. The complaint alleged that these charges impose an "excise tax" that is levied on a commodity, specifically "a kilowatt-hour of electricity." The petitioners argued that only customers residing in the distribution company service areas are subject to this alleged "tax" and that customers of municipal utilities are exempt. By the end of 1998, as a first step in the litigation process, the parties to the case worked on an "agreed statement of facts" to be submitted to the SJC. The case will continue in 1999.

[25] "NEES And National Grid To Merge In $3.2 Billion Transaction", NEES Press Release, Dec. 14, 1998.

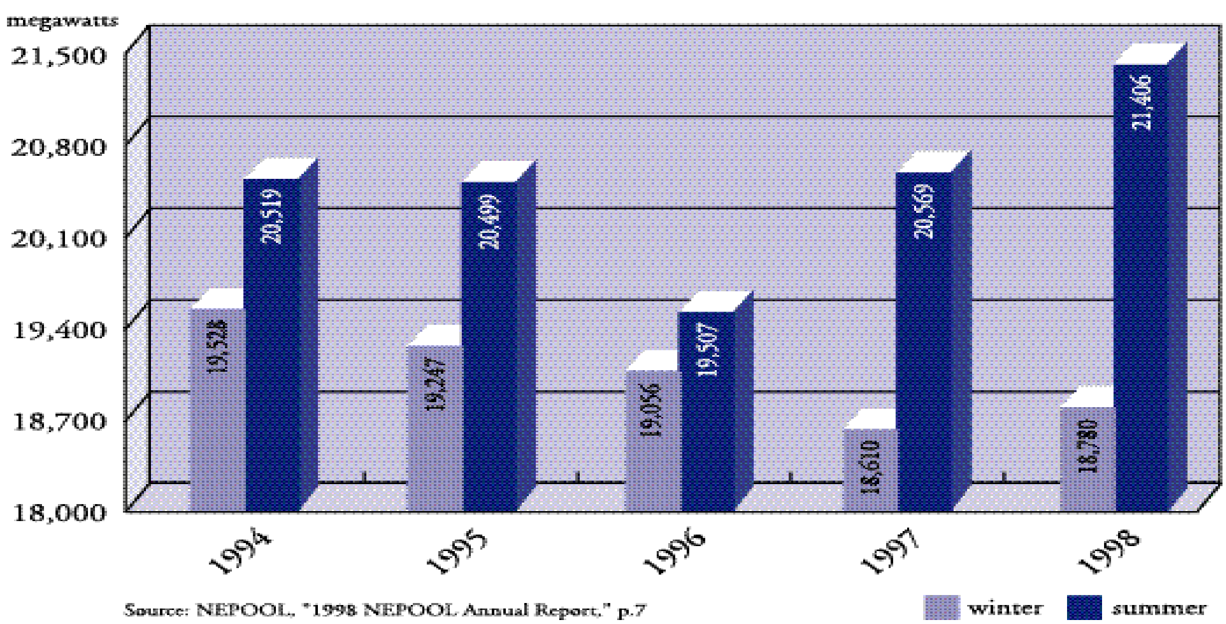
IV. ELECTRIC SYSTEM RELIABILITY

Successful wholesale and retail competitive markets depend on the reliability of the electric system. A competitive market that is robust and has a reliable transmission and distribution system will attract diverse generation sources. The ability to transmit the generated electricity, unconstrained to the extent possible by transmission limitations, can only be accomplished with a reliable transmission and distribution system. Competitive power suppliers desire a reliable system to compete for customer load and ensure that power flows to their customers. In addition, electric system reliability is extremely important to both consumers and businesses and to the security of the Massachusetts economy. This section assesses the reliability of the electric system, given the restructuring of the industry at the New England wholesale and Massachusetts retail distribution level.

4.1 New England's Bulk Power System

In New England, the bulk power supply system is operated as a single control area with limited interconnections with Canada and New York. NEPOOL has a historic peak load of just over 21,400 MW, with resulting capacity requirements for the region of approximately 25,000 MW. Collectively, NEPOOL participants own, operate or have entitlements in approximately 350 generators totaling about 23,500 MW of generating capacity as of December 1998. They also own and operate over 1,800 miles of the 345 kV transmission lines, the backbone lines of the system.[26] The New England transmission system was designed and constructed as a fully integrated network that allows New England generators to produce electricity that freely flows from any point on the system to any other point on the system. Figure 4.1 shows NEPOOL's seasonal peak demand loads from 1994-1998.

Figure 4.1: NEPOOL Seasonal Peak Demand, 1994-1998



[26] NEPOOL, "1998 NEPOOL Annual Report," p.3.

4.2 Wholesale Reliability – Resource Adequacy

Reliability of the Bulk Power Electric System Remained a Top Priority.

ISO-New England assumed responsibility for the operation of the New England bulk power market from NEPOOL in July 1997. ISO-New England's primary responsibility is to ensure the reliability of grid operations by providing an adequate supply of resources and maintaining transmission system integrity. The standard of reliability ISO-NE continues to be the "one day in ten years" standard set by the North American Reliability Council (NERC). This statistical standard was adopted by NERC shortly after its formation due to the massive northeast blackout in November 1965. The standard dictates that systems will be designed, constructed, and operated in a manner that ensures that a major system disturbance occurs no more frequently than one day in ten years. This standard did not change even though the FERC order 888 opened wholesale competition.

Available Resource Adequacy Targets Were Determined.

In order to meet the "one day in ten years" reliability standard, adequate resources must be available to allow for the unavailability of some resources due to necessary maintenance outages or to unavoidable forced outages. In 1998, ISO-New England worked closely with NEPOOL's Market Reliability Planning Committee (MRPC) which is responsible to determine the minimum amount of resources required to meet the reliability standard. The total amount of required resources is known as Objective Capability. This requirement ensures that there is a margin of excess generation capacity to meet the systems peak load. Each NEPOOL participant supports the total regional requirement in proportion to its load responsibility. Based on the Objective Capability standard, each generation service provider is required to maintain a certain amount of generating capability or Installed Capability (ICAP) Requirement. The ICAP market, administered by the ISO, became operational on April 1, 1998.

In 1998, the MRPC, along with other committees, considered appropriate measures to qualify those resources that can be counted toward meeting a NEPOOL Participant's ICAP requirement. Also, periodic audits of generating capability will be more rigorous than they have been in the past. A resource will lose its ICAP credit if it fails to demonstrate its claimed capability during a capability audit. Previously, a resource could continue to be counted as ICAP over a period of more than a year after its first audit failure. The shortening of that period to a matter of weeks will not only provide an impetus to the competitive market for ICAP, but it will also encourage a generator owner to maintain its facility to preserve its ICAP credit.[27]

[27] In 1998, various NEPOOL committees began discussions on imposing a "deliverability" requirement on resources as a pre-condition for ICAP credit. This criteria would ensure that a resource is able to deliver energy to load when it is called upon to do so, thus discouraging the construction of generation resources merely to market them as ICAP. No final decisions were made in 1998 on this proposal, but discussions continue and the situation should be finalized as part of the on-going negotiations aimed at developing a Congestion Management System (CMS) for New England. The CMS is currently scheduled to be filed for approval with FERC in the fall of 1999.

Operating Reserve Resource Practices Were Maintained.

ISO-New England continued the practice of maintaining adequate operating reserve resources to make up for any power plant or transmission line that unexpectedly goes out of service. This operating reserve equals the energy output of the single largest source of power providing electricity to the grid, plus one-half the second largest source. Typically, ISO-New England maintains an operating reserve margin of about 1900 MW. These reserves include units that can increase generation or start up and begin to generate power within 10 and/or 30 minutes.

ISO Managed Automatic Generation Control.

Another important tool, from a resource adequacy and a reliability standpoint, which ISO-New England controls is known as Automatic Generation Control (AGC) market. Certain units equipped with AGC can increase or decrease their level of output within a quick timeframe by a remote direction from ISO operators. In part from AGC contributions, the ISO can continually balance load and generation for the New England Control Area. This enables New England to maintain energy interchange with neighboring control areas (New York and New Brunswick) within the limits that conform to NERC standards. In the new bid-based market, the AGC units will submit daily bids to ISO-New England for this ancillary service.

Emergency Operating Procedures Were Continued and Implemented.

Under various emergency conditions, ISO-New England has the authority to procure emergency power from other power pools and perform other activities that increase supply or decrease demand. This critical operating procedure is known as Operating Procedure No. 4 (OP 4), “Action During a Capacity Deficiency.” Historically, NEPOOL has had more installed resources than required to meet Objective Capability. In addition, it has managed its generator maintenance scheduling to maximize the resources available during peak load periods. Actual OP 4 incidents have therefore not been frequent. Table 4.1 lists the number of OP 4 incidences since 1990. In 1998, ISO-New England implemented OP 4 measures 5 times. Many factors such as extreme weather conditions affect the need for emergency actions. However, the frequency of such incidents can be a useful indicator to signal a reduction in installed resource excess, although the frequency is not an absolute value of a reliability indicator. (In 1996, OP-4 procedures were implemented only within the state of Connecticut rather than the region due to CT’s unique conditions associated with the outage of its nuclear facilities.)

Table 4.1: 1990-1998 Capacity Deficiencies

1990	4
1991	5
1992	2
1993	1
1994	2
1995	9
1996	2
1997	5
1998	5

Source: ISO-New England

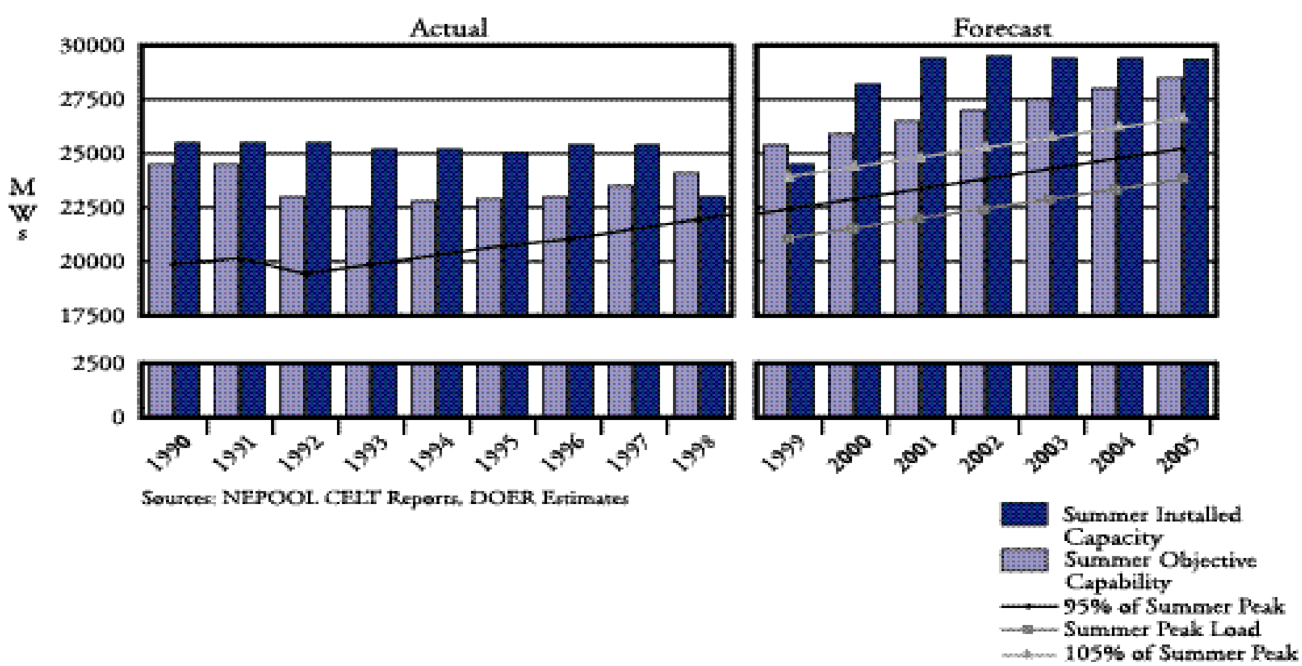
Market Rules Require Resource Performance and Monitoring.

Although, with the exception of the ICAP market, the new bid based markets did not open in 1998, NEPOOL established new market rules that supported the ISO's responsibilities and authority for a reliable system and in December 1998, FERC conditionally accepted the market rules. These rules describe how the markets will operate, define the bidding process for each market, how prices are determined, settlement procedures, sanctions for violations of the rules, requirements for resource performance and monitoring, and contracting procedures. For example, Market Rule No. 13 defined sanctions that ISO-New England may impose on a NEPOOL participant that fails to comply with NEPOOL rules or ISO instructions, including a failure to comply with a market power mitigation remedy. Market Rule No. 14 is intended to require a Participant to forego compensation for a resource that fails to perform in accordance to parameters established for the resource by the Participant's bid.[28]

Proposed Power Plants Will Add to New England's Generation Resources.

Previously mentioned in this report is the fact that over 30,000 MW of new power plants are proposed. Although not all proposed plants will be built, the ones that are built will add to New England's generation resource base. Older plants, which may be less efficient or more expensive than new plants, may close or be retired gradually. Figure 4.2 compares DOER's expectations of summer peak load and a plus or minus 5% sensitivity bandwidth from 1999-2005, to summer installed capability and objective capability, which include DOER's estimates of the most likely[29] additions to generation in 1999, 2000, and 2001. As shown, summer objective capability and summer installed capability are expected to exceed load in all years.

Figure 4.2 Summer Peak Load and Summer Capability



[28] NEPOOL FERC filings.

[29] Most likely additions are those that have completed their required applications for service with NEPOOL and have received approval, and have or shortly will commence construction.

4.3 Wholesale Reliability - Transmission

Historically, New England's transmission reliability has been achieved through the coordinated design and construction of the interconnected bulk power system. NEPOOL's criteria in performing System Impact Studies (SIS) for new generators were to ensure that the interconnection of a new generator did not adversely affect reliability and stability of the transmission system. In such a scheme, each new generator was responsible for any transmission upgrades needed to maintain the transmission system at its state prior to interconnection of the new generator and therefore was completely integrated into the system. Generators were able to produce power that freely flowed from any one point in the system to another. As a result, the New England transmission system was relatively unconstrained and transmission congestion within the NEPOOL control area was not a significant problem.

FERC Rejected the "Full Integration" Transmission Requirement.

In October 1998, FERC noted in its order in which FERC conditionally accepted parts of NEPOOL's restructuring compliance filing that NEPOOL's existing SIS criteria were cumbersome and ineffective. In particular, FERC stated that,

> Currently, NEPOOL's new generation requests total approximately 30,000 MW of capacity. Since the existing resources within NEPOOL (25,000 MW) are presently in general equilibrium with load and reserve requirements, if all these generating projects are developed, there would be a surplus of generating capacity in NEPOOL. Accordingly, it is unlikely that all of these generation projects will be constructed and, if constructed, it is likely that many will displace more expensive resources in serving existing load. If transmission expansion were based on the unrealistic assumption that all planned projects will be constructed and that all need a separate and exclusive firm transmission path to reach all load in NEPOOL, the transmission system would be significantly oversized.[30]

FERC rejected the "full integration" requirement as unnecessary, because in a more competitive wholesale market there will not longer be a linking of a particular generator to a particular load under NEPOOL's restructuring proposal. FERC allowed ISO-New England to limit the SIS analysis to the system reliability, stability and operating considerations of the local area of interconnection.

Transmission Is Likely To Become Constrained.

For a variety of reasons, transfer capacity of the existing transmission system, will probably become constrained, at certain times of the year. One reason is that a bid-based market system whereby, for the most part, generators are dispatched according to bid prices, may cause several low-priced generators in an area to compete for limited transmission capacity thereby limiting their ability to sell power in other parts of New England.

Another reason is that a large portion of the 30,000 MWs of new proposed generation is clustered in Maine and Massachusetts (see Appendix F). If many of these additional units come on line in one

[30] FERC, Docket No. ER98-3853-000, "Order Conditionally Accepting Compliance Filing, as Modified, and Accepting, in Part, and Rejecting, in Part, Proposed Tariff Changes, as Modified," October 29, 1998.

area and transmission is not expanded, it is likely that during certain times, there may be transmission constraints.

NEPOOL Began Development of a Transmission Congestion Management Plan.

For a variety of reasons, including FERC orders, NEPOOL began a stakeholders process in 1998 to develop a Congestion Management System (CMS) plan. Among the goals were: limit entry barriers; create proper price signals for use of transmission and expansion of generation and transmission in all relevant markets; maintain system reliability; facilitate efficient system operations; and create sufficient incentives for the construction of transmission when appropriate.

A "white paper" encapsulating the ideas developed in Phase I of this CMS process was filed with FERC on March 31, 1999. This filing suggests a Phase II – development of the details of this plan (as approved by FERC) and an implementation schedule. Phase II is to be filed with FERC in September 1999.

NEPOOL Committees Responsible for Transmission Reliability Planning.

Although the ISO-New England manages reliability of the electric system, NEPOOL committees are also responsible for ensuring a reliable transmission system into the future. This responsibility is entrusted to two NEPOOL Committees. The Regional Transmission Planning Committee (RTPC), in conjunction with ISO-New England, recommends actions on such items as:

> overall direction of joint studies of transmission facilities and the development of a regional transmission plan in order to achieve the objectives of NEPOOL;
>
> following appropriate studies proposed reliability standards for the bulk power system of NEPOOL;
>
> coordinating the review of proposed transmission plans of Participants; and
>
> to the extent appropriate, establishing criteria, guidelines and methodologies to assure consistency in monitoring and assessing conformance of Participant and regional transmission plans to accepted reliability criteria.

The Regional Transmission Operations Committee (RTOC), in conjunction with ISO-New England, is responsible for recommending actions on such things as:

> necessary studies and establishment or approval of procedures to ensure the reliable operation and facilitate the efficient operation of the NEPOOL Control Area bulk power supply;
>
> coordination of studies of, and provision of information to Participants on, maintenance schedules for the supply and demand-side resources and transmission facilities of Participants; and

to the extent appropriate, assuring the reliable operation of bulk power supply of NEPOOL Control Area, establishment of or approval of reasonable standards, criteria and rules relating to protective equipment, switching, voltage control, load shedding, emergency and restoration procedures, and the operation and maintenance of supply and demand-side resources and transmission facilities of the Participants.[31]

4.4 Distribution Reliability

The DTE is responsible for ensuring that distribution reliability standards are met by distribution companies. They do so through quality of service reviews and can initiate investigations and formal proceedings if they believe distribution reliability standards are not met. For example, in the past DTE has held investigations on distribution companies' restoration of power after winter storms. In 1998, DTE also concentrated on ensuring that Massachusetts distribution companies and generators were preparing their computer application systems to recognize the date change from 1999 to 2000, an action referred to as Y2K readiness, so that generation, transmission, and distribution systems remain operational.

DTE Assessed the Y2K Readiness Activities of Distribution Companies.

Since early 1998, DTE has monitored and evaluated the Massachusetts electric utility industry's activities in preparation of Y2K. DTE has held several technical workshops with industry participants. Companies taking part in the workshops discussed their Y2K plans, learned from each other as to what needs to be done and how, and determined from DTE how the Department could assist them in making the Y2K rollover successful without major disruptions. DTE also assessed the Y2K readiness of critical interface partners of the electric utility industry such as telecommunication companies, natural gas suppliers, and cable companies. Additionally, DTE has required each distribution company to submit by the end of the first quarter of 1999:

quarterly reporting (commencing in December 1998) as to the status of their Y2K compliance/ readiness activities;
a letter from its Chief Executive Officer regarding the status and date of Y2K readiness;
bill inserts/newsletter to customers regarding itsY2K activities;
information regarding Y2K audits that were performed by third party entities; and
Y2K contingency plans.

Based on the information provided to DTE as of February 1999, the companies have:

commenced their Y2K activities during or prior to 1997 (most started in 1995);
completed or nearly completed the inventory assessment, and testing phases of their information technology systems;
completed their inventory and assessment phases of the components with "embedded chips";
performed their own tests (and have not relied solely upon vendor Y2K certification);
completed approximately 75% or greater of the testing of these components;
plan to complete the first draft of their contingency plans by the 1st quarter of 1999; and

[31] Excerpts from Restated NEPOOL Agreement.

plan to complete testing and remediation and by “Y2K-prepared” by mid-1999.[32]

Municipal Electric Companies’ Y2K Readiness is Almost Complete.

The Department conducted a special Y2K technical workshop for the municipal electric entities that evaluated their efforts. Based on the workshop and subsequent discussions with these entities, DTE believes that the municipal electric utilities have almost completed their Y2K efforts.

DTE Met with ISO-New England on Y2K Readiness.

DTE also met with ISO-New England on a frequent basis regarding Y2K generation and transmission issues. Based on discussions and assurances and information provided, the DTE believes that electric restructuring has had no impact on the power generation companies’ ability to be Y2K ready. Additionally, DTE staff conducted several site visits to assess the Y2K readiness of several generation facilities and plans to visit additional generators as well as transmission facilities.

DTE corresponded with the Y2K technical staff from Hydro-Québec. Because it can provide up to 2,210 MW to New England through two voltage transmission links, Hydro-Québec is an important asset in the New England power generation equation. However, ISO New England is planning to minimize transfers between NEPOOL and other regional entities during the December 31, 1999 - January 3, 2000 rollover period and is, therefore, limiting Hydro-Québec’s transmission to New England to about 600 MW.[33] Nevertheless, DTE will continue to get updates and assurances from Hydro-Québec and ISO-New England.

[32] DTE website and DOER discussions with DTE staff.

[33] DTE notes that peak electricity demand during the December 31, 1999 11 p.m. to January 2000, 1 a.m. timeframe is expected to be approximately 14,000 MW. Total New England generating capacity is about 25,000-26,000 MW.

V. LIKELY FUTURE DEVELOPMENTS

Accelerated Retail Competition.
More customers should move to retail competitive suppliers over time. Decreases in transition charges have allowed for increases in standard offer generation prices, which should make it possible for competitive suppliers to enter the retail market. Also, municipalities, trade organizations, and other large electric customers are looking at bidding out their electricity load to competitive suppliers.

Lower Rates.
Overall retail rates for standard offer customers will be further reduced by 5% on September 1, 1999, bringing the total rate reduction to 15%. Moreover, with respect to generation supply, power plant owners will likely reduce costs and improve operating efficiencies to meet competitive prices of new plants thus lowering the market price of generation.

Performance Based Rates for Distribution Companies.
In order to reduce distribution company service costs while maintaining appropriate levels of reliability, the Act authorized the DTE to promulgate rules and regulations establishing performance based rates (PBR) for each distribution company. Under PBR, distribution company efficiencies are rewarded while poor performance is penalized.

Increased Wholesale Price Volatility.
Hourly wholesale spot market electricity prices are likely to become more volatile as a result of the change from cost based to bid based pricing. However, supply contracts and financial hedging instruments will allow retailers to offer fixed prices to consumers.

Industry Convergence.
Distribution companies are expected to combine with gas companies, telecommunication companies, and cable operators, among other possibilities. This convergence of "network industries" should lower costs through increased efficiencies in "shared services", such as administration, billing, and customer services. Convergence can provide greater customer convenience through "one-stop-shopping."

Improved Economic and Job Creation Activities.
Restructuring should increase the level of economic activity and job creation in the Commonwealth. Competitive pressures in generation and consolidations from mergers and acquisitions may result in job reductions in electric industry employment. However, new electricity-related companies entering the market will offset some of these reductions by increasing services and employment.

New Product Developments.
Early indications suggest that two main groups of products and services are emerging. The first group contains energy-related products and a variety of energy efficiency and engineering services. The second contains technology-related products and services, such as cable television, Internet, and local telephone service.

Improved Air Quality.
The vast majority of new power plants proposed for the region are highly efficient natural gas-fired plants. Although not all the proposed projects will be completed, it is expected that enough new capacity will be constructed to force the retirement or reduced use of some older, less efficient oil-fired plants. Furthermore, nitrogen oxide limits specified in the Federal Clean Air Act Amendments are scheduled to begin in the summer of 1999.

Additional Renewable Energy Sources.
Provisions contained in the Act to promote renewable energy sources as well as "green" marketing offers by competitive suppliers and increased awareness from customer information disclosure will help spur the construction of more renewable capacity.

Further Choice in Reliability Levels.
As competitive suppliers tailor products more closely to the needs of customers, some, particularly industrial customers, will be able to choose various levels of interruptions to power and therefore lower their electricity costs.

Potential Evolution of the Management of the New England Transmission System.
There has been debate at the Federal Energy Regulatory Commission about various alternate approaches to operating transmission systems. One approach is a non-profit ISO managing transmission assets with ownership remaining with the incumbent utilities - New England's current system. Another approach is to create a for-profit transmission company that acquires or retains ownership of all transmission, a "transco". Some parties who may want to revisit the overall structure of the ISO claim that the ISO New England has little authority or incentive to require the construction of new transmission.

Conclusion

The most widely recognized accomplishment during the first year of the restructured electric industry in Massachusetts was the reduction in every customer's overall bill of 10%, a change that saved customers approximately $450 million in 1998. The retail competitive market developed quite slowly in the first year. Although several types of private and non-profit aggregation groups formed to increase buying power of customers, at year end only 1% of the state's electric demand was being purchased by retail customers directly from competitive suppliers.

Nevertheless, major changes were taking place behind the scenes to move the electricity market toward much greater reliance on competitive forces. Utility companies made significant progress in the divestiture of their power plants and power supply contracts. The generation portion of the electric industry now has new owners who will compete for customers and the concern that distribution companies might use their monopoly of the wires to interfere with competition has been virtually eliminated. An added bonus from sale of power plants was a rapid reduction in stranded costs facing electric ratepayers, a 29% reduction on a state-wide basis. Over the course of the year, the DTE promulgated comprehensive regulations to allow choice of supplier for all retail customers and issued licenses to 22 competitive suppliers wishing to serve those customers.

In addition, prompted by restructuring legislation enacted in most of the New England states, developers announced plans to build over 30,000 MW of new power plants across the region. Over time, additional power plants are expected to drive down the market price for power. In another important structural innovation, three distribution companies proposed to merge and consolidate their operations.

In all, 1998 brought unprecedented changes to the electric industry in Massachusetts. These changes have already delivered significant benefits to electricity customers and set the stage for the realization of even greater benefits as retail competition grows in the years ahead.

APPENDIX A

MILESTONES

in

MASSACHUSETTS' ELECTRIC RESTRUCTURING

I. DELIBERATION AND DEBATE (1993-1995)

1993 DECEMBER	**MARKET REFORM TASK FORCE**
Governor convenes group of electric industry stakeholders, co-chaired by the DOER Commissioner and DPU Chairman, to suggest modifications to existing regulatory system to lower electricity costs.	

1994 JULY	**TASK FORCE REPORT**
Market Reform Task Force Report identifies strategies to lower retail rates and bills for customers; includes set of principles termed "Rules for the Wires" for introducing competition into retail electric markets.	

1995 FEBRUARY	**INQUIRY into RESTRUCTURING, D.P.U. 95-30**
DPU opens investigation into how electric restructuring promotes competition, economic efficiency, and expands customer benefits; customer options for choosing electricity suppliers; restructuring implementation; and, appropriate regulatory mechanisms.	

1995 JULY	**NEGOTIATED PRINCIPLES**
A broad-based coalition of utilities, consumers and environmentalists, coordinated by DOER, files with the DPU principles to guide the introduction of competition and customer choice to retail electric markets.	

1995 AUGUST	**DPU ORDER, D.P.U. 95-30**
DPU specifies seven principles to guide future competitive electric industry and five more principles to guide transition to more competitive industry. DPU requires companies to file restructuring proposals by February 1996.	

1995 DECEMBER	**SENATE COMMITTEE on POST AUDIT and OVERSIGHT REPORT**
In response to D.P.U. 95-30, Committee makes several policy recommendations and lists requisite legislative actions in report entitled, "A Prescription for Competition: The Restructuring of the Electric Utility Industry."	

II. INDUSTRY RESTRUCTURING INITIATIVES (1996-1997)

1996 FEBRUARY	UTILITY RESTRUCTURING PLANS
In accordance with D.P.U. 95-30, Boston Edison Co., Eastern Edison Co., Massachusetts Electric Co., and Western Massachusetts Electric Co., file restructuring plans.	

1996 FEBRUARY	DOER's "POWER CHOICE"
DOER submits to DPU its vision of a restructured electric industry that advocates voluntary divestiture of generation assets and mitigation of stranded costs.	

1996 MAY	EXPLANATORY STATEMENT and PROPOSED RULES, D.P.U. 96-100
In March, DPU opens inquiry, D.P.U. 96-100, to analyze the five restructuring plans. In May, DPU offers proposed rules for restructuring to "serve as reference point and to generate response and discussion."	

1996 SEPTEMBER	FIRST ELECTRICITY BUYING COOPERATIVE
Massachusetts Health and Educational Facilities Authority (HEFA) announces plans for new group purchase of electricity service for its nonprofit, charitable institutions.	

1996 OCTOBER	MASS. ELECTRIC SETTLEMENT
Mass. Electric Co., DOER, AG's Office and other parties file first restructuring plan settlement with DPU; includes agreements on rate reductions and generation divestiture.	

1996 DECEMBER	MODEL RULES and LEGISLATIVE PROPOSAL, D.P.U. 96-100
DPU presents Governor with "Electric Industry Restructuring Plan: Model Rules and Legislative Proposal," with restructuring elements framework and legislative proposal.	

1997 MAY	EASTERN EDISON SETTLEMENT
Eastern Edison Co. and Montaup Electric Co., DOER, AG's Office and other parties file restructuring plan settlement with DPU; includes same agreements on rate reductions and generation divestiture as Mass. Electric settlement.	

1997 JULY	BOSTON EDISON SETTLEMENT
Boston Edison Co., DOER, AG's Office and other parties file restructuring plan settlement with DPU; includes agreements on rate reductions and generation divestiture.	

1997 JULY	ISO-NEW ENGLAND CREATION
Independent System Operator of New England (ISO-NE) assumes management responsibility for New England's electric bulk power generation and transmission systems and administration of the region's open access transmission tariff.	

III. LEGISLATION (1997)

1997 FEBRUARY	GOVERNOR'S PROPOSED LEGISLATION
Governor files legislation to restructure the Massachusetts electric utility industry; includes 10% savings guarantee, incentives to divest generation assets and "reasonable opportunity" for utilities to recover stranded costs.	

1997 FEBRUARY	MASS. ELECTRIC PLAN APPROVED

1997 MARCH	JOINT COMMITTEE PROPOSED LEGISLATION
Committee outlines electric restructuring policy options for Legislature's consideration and proposes legislative package.	

1997 JULY	SENATE, GOVERNMENT REGULATIONS COMMITTEE LEGISLATION
Includes rate reductions, divestment, standard offer, renewables funding, and aggregation.	

1997 SEPTEMBER	HOUSE, GOVERNMENT REGULATIONS COMMITTEE LEGISLATION
Includes enhanced consumer education provisions, additional rate reductions, and moves Retail Access Date from January 1, 1998 to March 1, 1998.	

1997 NOVEMBER	ELECTRIC UTILITY RESTRUCTURING LAW
House and Senate Conference Committee negotiates and merges House and Senate bills into one bill. Legislature approves legislation to restructure electric industry and Governor signs bill into law on November 25, 1997. Includes 10% rate reduction in 1998 and 15% in September 1999; Retail choice for all on March 1, 1998; securitization; municipal aggregation; seven year standard offer; incentives for divestiture; rate unbundling; labor and municipal property tax protections; efficiency and renewables charges; and customer education.	

1997 DECEMBER	EASTERN EDISON PLAN APPROVED

1998 JANUARY	BOSTON EDISON PLAN APPROVED

IV. IMPLEMENTATION (1998)

1998 FEBRUARY	FINAL ORDER, DPU/DTE 96-100
The DTE issues final Order in DPU/DTE 96-100 and promulgates regulations and also finalizes regulations governing licensing of competitive suppliers and electricity brokers.	

1998 FEBRUARY	INTERIM APPROVAL OF UTILITY COMPANY PLANS
DTE issues interim approvals of restructuring plans of companies without approved settlements: Commonwealth Electric Company, Fitchburg Gas and Electric Company and Western Massachusetts Electric Company.	

1998 MARCH	RETAIL ACCESS DAY
March 1, 1998, customers are able to purchase generation service from entities other than traditional electric companies.	

1998 APRIL	FIRST NUCLEAR PLANT FOR SALE
Boston Edison Company seeks buyers for Pilgrim Nuclear Power Plant (670 MW).	

1998 MAY	SITHE ENERGIES BUYS BOSTON EDISON'S PLANTS
Boston Edison Co. finalizes sale of non-nuclear generating plants (about 2000 MW) to Sithe Energies, Inc. for $536 million, about 1.2 times book value.	

1998 SEPTEMBER	U.S. GEN. BUYS MASS. ELECTRIC'S PLANTS
Mass. Electric Co. finalizes the sale of non-nuclear generating plants and power contracts (about 5,000 MW) to U. S. Generating Company for $1.59 billion, about 1.5 times book value.	

END OF 1998	SOUTHERN ENERGY TO FINALIZE PURCHASE OF COMM. ELECTRIC'S PLANTS
Commonwealth Electric to finalize sale of plants (about 1000 MW) to Southern Energy Inc. for $462 million, about 6 times book value.	

1998 NOVEMBER	RESTRUCTURING STATUTE UPHELD
71% of voters vote Yes on ballot question #4 which keeps intact electric utility restructuring legislation passed in November 1997.	

Source: DOER

APPENDIX B — Stranded Cost Data for Electric Utilities in MA

Breakdown of Initial Transition Charges for Electric Utilities in Massachusetts
(Net Present Value, $ thousands)

	Fossil/Hydro Generation [1]	Nuclear Generation [1]	Regulatory Assets	Purchased Power [2]	Total Transition Charges	Total Excluding Reg. Assets
Divestitures Completed by 10/98						
Boston Edison	$555,398	$908,829	$63,248	$1,706,604	$3,234,079	**$3,170,831**
Cambridge Electric	$20,111	$99,758	($366)	$70,352	$189,854	**$190,221**
Commonwealth Electric	$39,842	$310,043	$59,165	$847,155	$1,256,204	**$1,197,040**
Massachusetts Electric	$1,111,090	$724,396	$181,904	$1,371,861	$3,389,251	**$3,207,347**
Total Completed	**$1,726,442**	**$2,043,026**	**$303,950**	**$3,995,972**	**$8,069,389**	**$7,765,439**
Divestitures Pending after 10/98						
Eastern Edison	$34,519	$446,271	$17,130	$93,287	$591,207	**$574,077**
Fitchburg Gas & Electric	$4,015	$8,655	$3,341	$75,315	$91,327	**$87,986**
Western Mass. Electric[3]	$16,349	$611,915	$116,434	$223,111	$967,809	**$851,375**
Total Pending	**$54,884**	**$1,066,841**	**$136,906**	**$391,713**	**$1,650,343**	**$1,513,438**
A. Grand Total	**$1,781,325**	**$3,109,867**	**$440,856**	**$4,387,685**	**$9,719,732**	**$9,278,877**
B.Percent of Total	**18.3%**	**32.0%**	**4.5%**	**45.1%**	**100.0%**	**95.5%**

Source: Schedule 1 of Company Settlement Filings/Compliance Filings; DOER analysis.

[1] Fossil-Hydro and nuclear generation estimates include both fixed and variable components. With the exception of Western Mass. Electric, utility transition charges assume no market value for owned generation.

[2] Above-Market Purchased Power transition charges are based on each utility's estimate of market value.

[3] Regulatory Assets for Western Mass. Electric includes potential deferred costs.

[4] Net Present Value in $1998 based on an 8% annual discount rate.

Projected Benefits of Non-Nuclear Generation Divestitures & Net Stranded Costs for Electric Utilities in Massachusetts (Net Present Value, $ thousands)

	Initial Transition Charges Excluding Reg. Assets	Estimated Benefits of Non-Nuclear Generation	Net Stranded Cost	Decrease as a Result of Divestitures
Divestitures Completed ***by 10/98***				
Boston Edison	$3,170,831	$464,051	$2,706,781	14.6%
Cambridge Electric	$190,221	$46,308	$143,913	24.3%
Commonwealth Electric	$1,197,040	$265,654	$931,386	22.2%
Massachusetts Electric [1]	$3,207,347	$1,766,752	$1,440,595	55.1%
A. Total Completed	**$7,765,439**	**$2,542,765**	**$5,222,674**	**32.7%**
Divestitures Pending after 10/98				
Eastern Edison [3]	$574,077	$43,912	$530,165	7.6%
Fitchburg Gas & Electric	$87,986	$13,026	$74,960	14.8%
Western Mass. Electric	$851,375	$63,043	$788,332	7.4%
B. Total Pending	**$1,513,438**	**$119,981**	**$1,393,456**	**7.9%**
C. Grand Total	**$9,278,877**	**$2,662,746**	**$6,616,131**	**28.7%**

Source: Schedule 1 of Company Settlement Filings/Compliance Filings, other company filings, and internal DOER estimates.

[1] Includes benefits of $386.5 million form divestitures of purchased power contracts.
[2] Assumes an average purchase price of $367/kWh for non-nuclear assets that have not been sold, based on the average purchase price received by other MA utilities.
[3] Includes actual proceeds from partial sale of non-nuclear assets.
[4] Net Present Value in $1998 based on an 8% annual discount rate.

Summary of Non-Nuclear Generation Asset Divestitures by Massachusetts Utilities

Sales Completed (10/98) [1]	Total Capacity (MW)	Net Book Value ($million)	Purchase Price ($ million)	Purchase Price ($/kWh)	Purchase Price (x NBV)	Purchasing Company	MA Share	MAShare NBV ($million)	MA Share Purchase Price ($million)
Boston Edison	1,987	$450.0	$536.0	$269.8	1.19	Sithe Energies	100.0%	$450.0	$536.0
Commonwealth Electric	984	$79.0	$462.0	$469.5	5.85	Southern Energy	100.0%	$79.0	$462.0
Montaup Electric **[2,3]**									
Canal 2 (50%)	280	$41.3	$75.0	$267.9	1.82	Southern Energy	59.0%	$24.4	$44.3
Wyman 4	416	$1.8	$4.2	$257.7	2.33	FLP Group	59.0%	$1.1	$2.5
New England Power Co.	4,000	$1,100.0	$1,590.0	$397.5	1.45	U.S. Generating Co.	72.6%	$798.6	$1,154.3
Sub-total Completed	**7,267**	**$1,672.1**	**$2,667.2**	**$367.0**	**1.60**			**$1,353.0**	**$2,199.1**
Sales Pending after (10/98) [4]									
Fitchburg Gas & Electric	47	*$4.4*	*$17.3*	*$367.0*	*3.94*	*Estimated*	*100.0%*	*$4.4*	*$17.3*
Montaup Electric Somerset	160	*$23.0*	*$58.7*	*$367.0*	*2.55*	*Estimated*	*59.0%*	*$13.6*	*$34.7*
Western Mass. Electric	545	*$57.1*	*$200.0*	*$367.0*	*3.50*	*Estimated*	*100.0%*	*$57.1*	*$200.0*
D. Sub-total Pending	**752**	*$84.5*	*$276.1*	*$367.0*	*3.27*			*$75.1*	*$252.0*
Total Non-nuclear generation	**8,020**	*$1,756.6*	*$2,943.3*	*$367.0*	*1.68*			*$1,428.1*	*$2,451.1*

[1] Capacity, Net Book Value, and Purchase Price data based on Company press releases unless otherwise noted above.
[2] Net Book Value based on 1997 FERC Form 1.
[3] Mass. Share based on Requirements Sales for Resale from 1997 FERC Form 1.
[4] Capacity and Net Book Value data based on 1997 FERC Form 1.
Average Purchase Price data estimated based on average purchase price (in $/kWh) of completed sales.

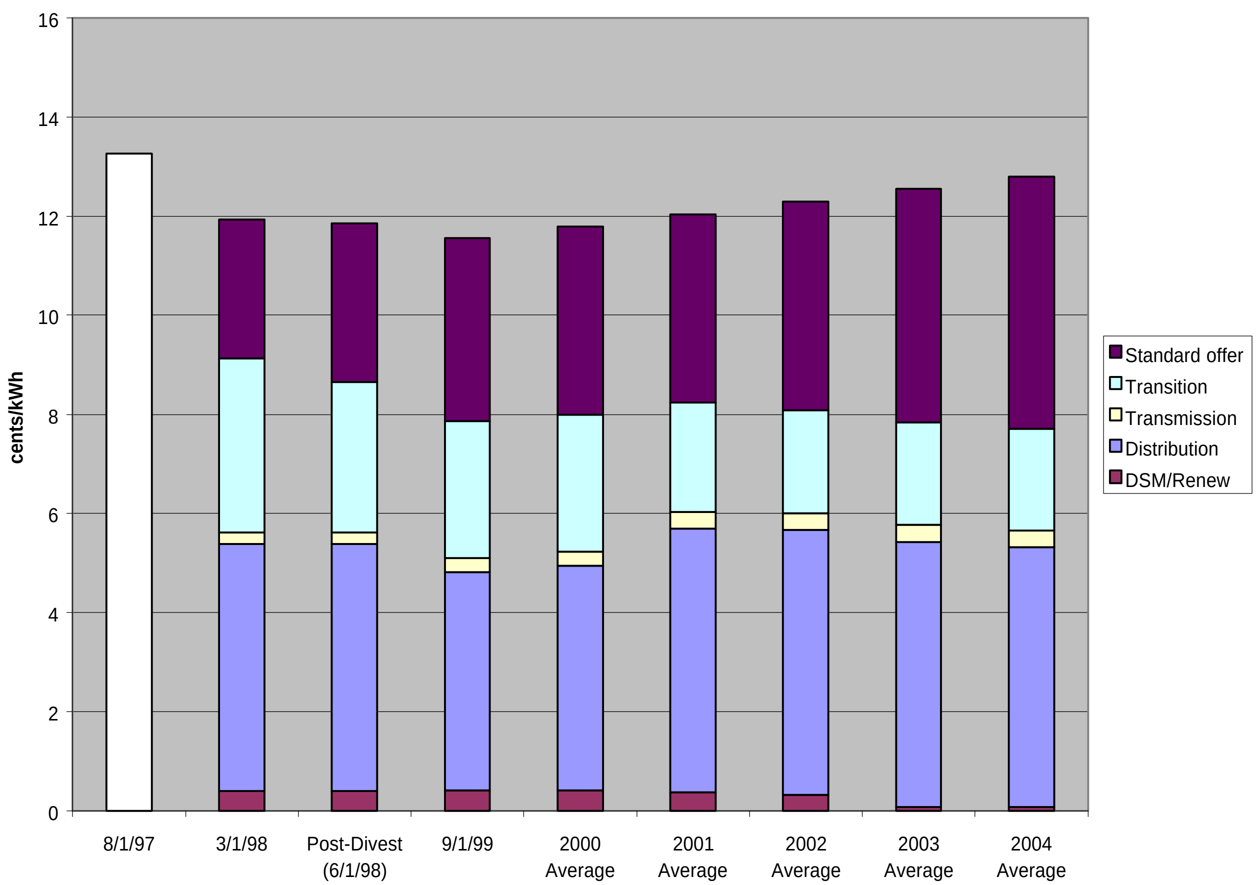
APPENDIX C – UNBUNDLED PRICE TRAJECTORY (cents/kWh)

600 kWh Residential Customer
Distribution Companies

Boston Edison

	8/1/97	3/1/98	Post-Divest 6/1/98	9/1/99	2000 Avg.	2001 Avg.	2002 Avg.	2003 Avg.	2004 Avg.
Standard Offer		2.800	3.200	3.690	3.800	3.800	4.200	4.700	5.100
Transition		3.510	3.030	2.760	2.760	2.208	2.084	2.076	2.051
Transmission		0.244	0.244	0.279	0.287	0.337	0.338	0.339	0.332
Distribution		4.972	4.972	4.410	4.533	5.321	5.339	5.352	5.245
DSM/Ren.		0.405	0.405	0.410	0.410	0.370	0.325	0.075	0.075
Total	13.256	11.931	11.851	11.550	11.790	12.036	12.287	12.543	12.804

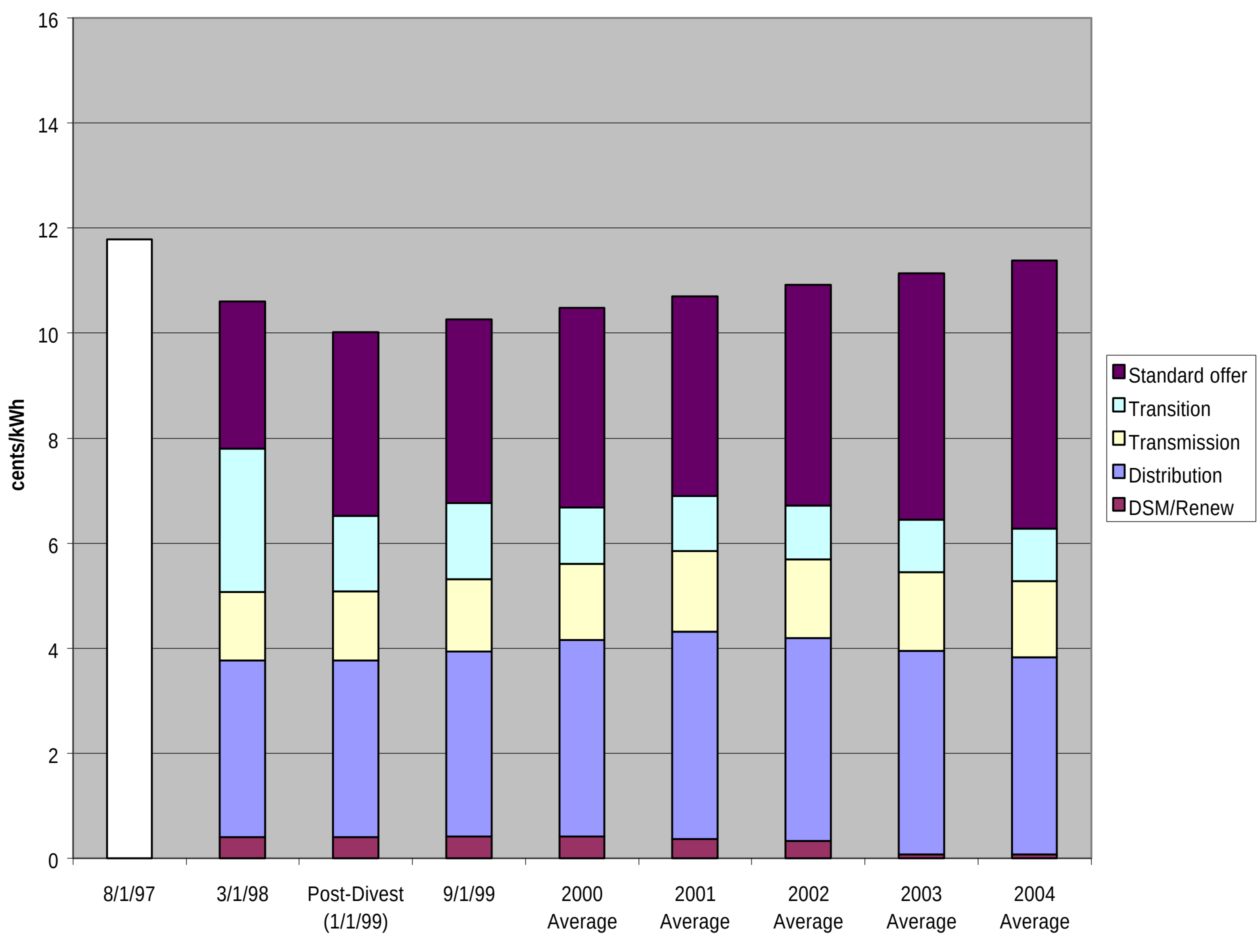
Sources: Distribution Rate Filings, DOER Forecasts



Cambridge Electric

	8/1/97	3/1/98	Post-Divest 1/1/99	9/1/99	2000 Avg.	2001 Avg.	2002 Avg.	2003 Avg.	2004 Avg.
Standard Offer		2.800	3.500	3.500	3.800	3.800	4.200	4.700	5.100
Transition		2.730	1.447	1.451	1.070	1.046	1.029	1.000	0.995
Transmission		1.310	1.310	1.371	1.453	1.532	1.500	1.502	1.456
Distribution		3.356	3.361	3.530	3.743	3.946	3.863	3.868	3.750
DSM/Ren.		0.405	0.405	0.410	0.410	0.370	0.325	0.075	0.075
Total	11.779	10.601	10.023	10.262	10.476	10.694	10.917	11.145	11.377

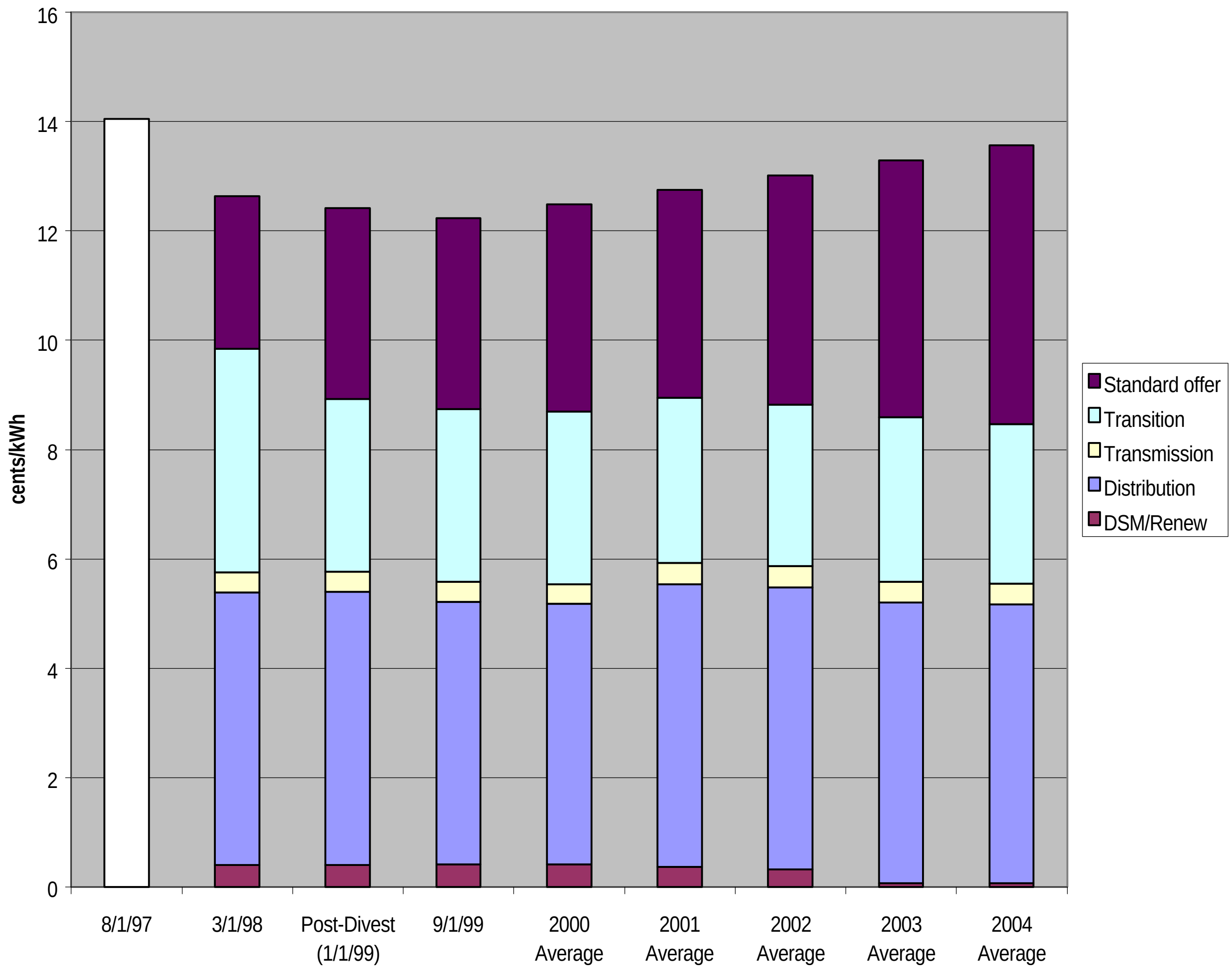
Sources: Distribution Rate Filings, DOER Forecasts



Commonwealth Electric

	8/1/97	3/1/98	Post-Divest 1/1/99	9/1/99	2000 Avg.	2001 Avg.	2002 Avg.	2003 Avg.	2004 Avg.
Standard Offer		2.800	3.500	3.500	3.800	3.800	4.200	4.700	5.100
Transition		4.080	3.159	3.141	2.935	2.905	2.812	2.896	2.801
Transmission		0.372	0.372	0.361	0.372	0.395	0.395	0.391	0.389
Distribution		4.985	4.990	4.826	4.976	5.283	5.286	5.228	5.202
DSM/Ren.		0.405	0.405	0.410	0.410	0.370	0.325	0.075	0.075
Total	14.046	12.642	12.426	12.238	12.493	12.753	13.019	13.290	13.567

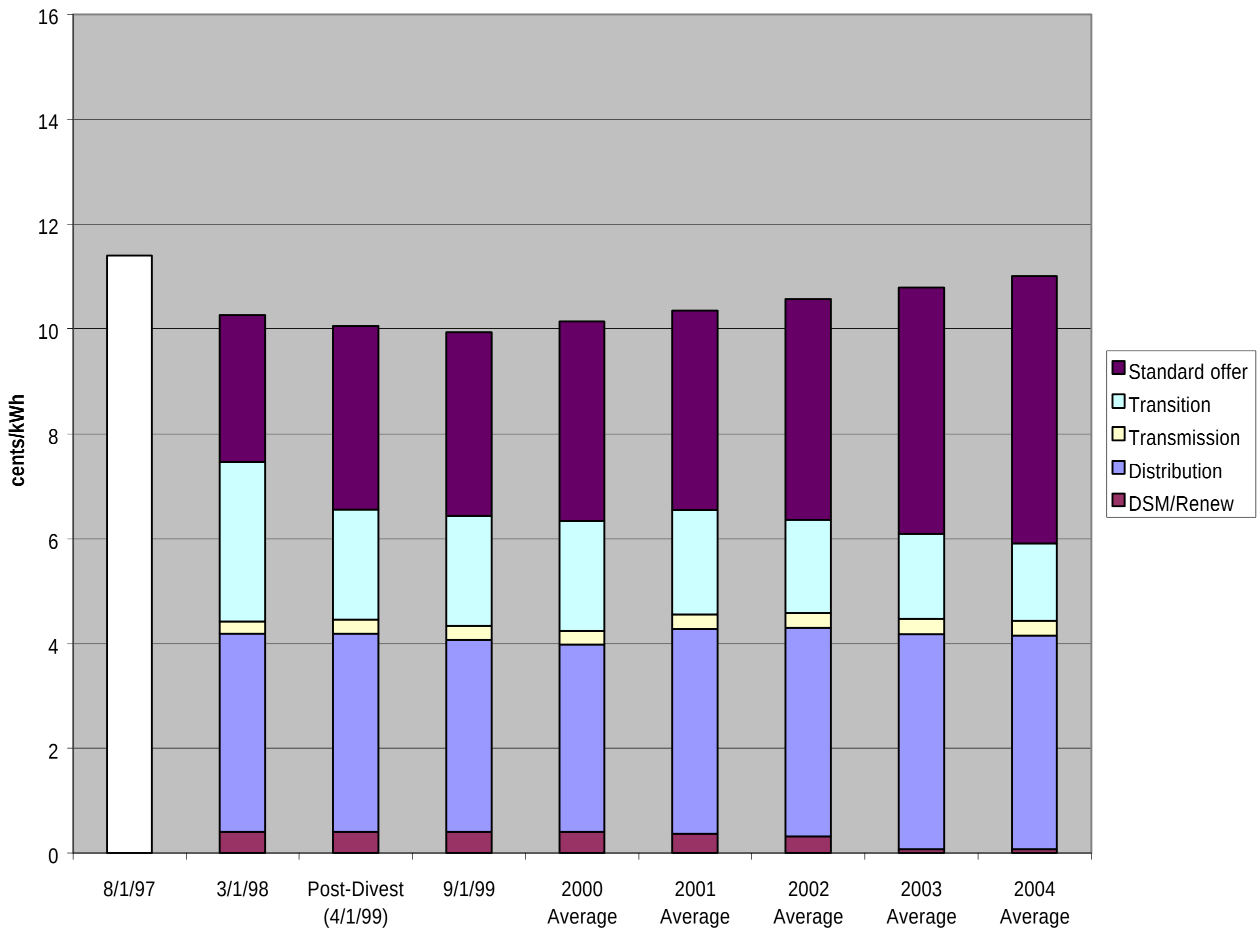
Sources: Distribution Rate Filings, DOER Forecasts



Eastern Edison

	8/1/97	3/1/98	Post-Divest 4/1/99	9/1/99	2000 Avg.	2001 Avg.	2002 Avg.	2003 Avg.	2004 Avg.
Standard Offer		2.800	3.500	3.500	3.800	3.800	4.200	4.700	5.100
Transition		3.040	2.100	2.100	2.100	1.996	1.782	1.616	1.471
Transmission		0.233	0.266	0.258	0.252	0.276	0.281	0.290	0.288
Distribution		3.779	3.784	3.661	3.574	3.906	3.975	4.102	4.074
DSM/Ren.		0.405	0.405	0.410	0.410	0.370	0.325	0.075	0.075
Total	11.397	10.257	10.055	9.930	10.137	10.348	10.563	10.783	11.008

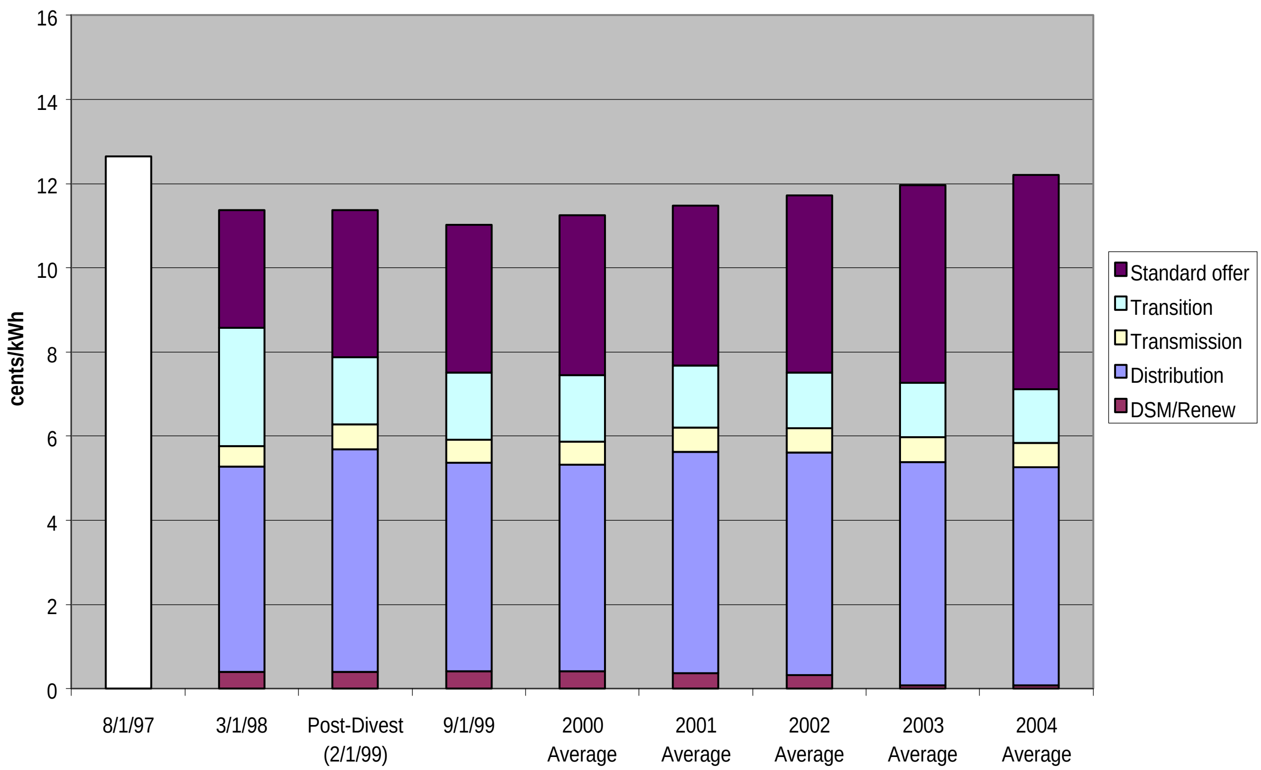
Sources: Distribution Rate Filings, DOER Forecasts



Fitchburg Gas & Electric

	8/1/97	3/1/98	Post-Divest 2/1/99	9/1/99	2000 Avg.	2001 Avg.	2002 Avg.	2003 Avg.	2004 Avg.
Standard Offer		2.800	3.500	3.500	3.800	3.800	4.200	4.700	5.100
Transition		2.820	1.600	1.600	1.580	1.474	1.322	1.296	1.269
Transmission		0.479	0.586	0.552	0.547	0.585	0.589	0.591	0.578
Distribution		4.875	5.288	4.954	4.908	5.250	5.283	5.301	5.189
DSM/Ren.		0.405	0.405	0.410	0.410	0.370	0.325	0.075	0.075
Total	12.644	11.379	11.379	11.016	11.245	11.480	11.719	11.963	12.212

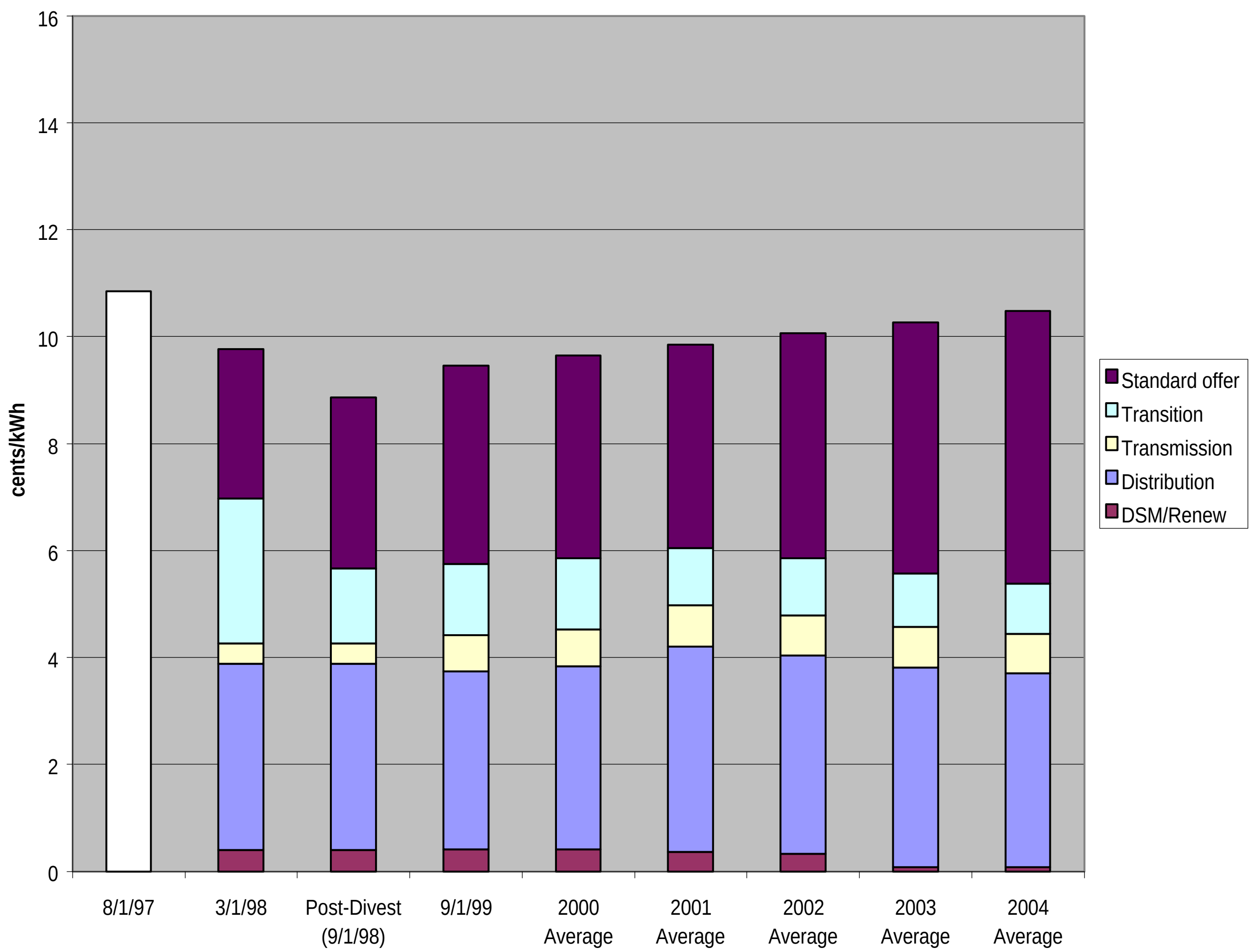
Sources: Distribution Rate Filings, DOER Forecasts



Massachusetts Electric

	8/1/97	3/1/98	Post-Divest 9/1/98	9/1/99	2000 Avg.	2001 Avg.	2002 Avg.	2003 Avg.	2004 Avg.
Standard Offer		2.800	3.200	3.707	3.800	3.800	4.200	4.700	5.100
Transition		2.707	1.407	1.334	1.324	1.073	1.073	1.003	0.943
Transmission		0.384	0.384	0.673	0.692	0.775	0.750	0.754	0.733
Distribution		3.470	3.470	3.331	3.425	3.835	3.710	3.735	3.630
DSM/Ren.		0.405	0.405	0.410	0.410	0.370	0.325	0.075	0.075
Total	10.851	9.766	8.866	9.454	9.651	9.852	10.058	10.267	10.481

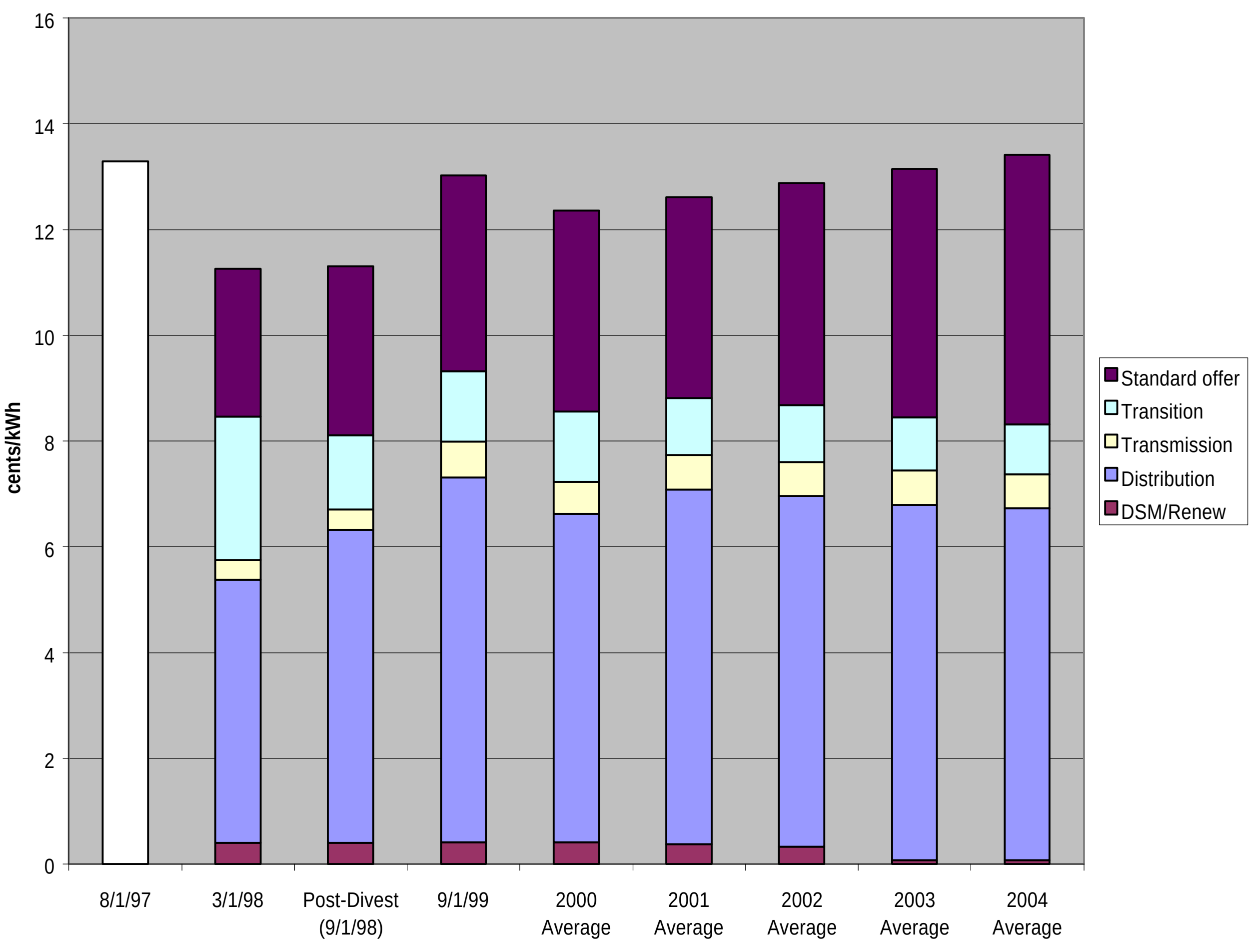
Sources: Distribution Rate Filings, DOER Forecasts



Nantucket Electric

	8/1/97	3/1/98	Post-Divest 9/1/98	9/1/99	2000 Avg.	2001 Avg.	2002 Avg.	2003 Avg.	2004 Avg.
Standard Offer		2.800	3.200	3.707	3.800	3.800	4.200	4.700	5.100
Transition		2.707	1.407	1.334	1.324	1.073	1.073	1.003	0.943
Transmission		0.384	0.384	0.673	0.606	0.655	0.646	0.654	0.648
Distribution		4.960	5.917	6.903	6.216	6.716	6.632	6.712	6.652
DSM/Ren.		0.405	0.405	0.41	0.41	0.37	0.325	0.075	0.075
Total	13.298	11.256	11.313	13.026	12.356	12.613	12.876	13.144	13.418

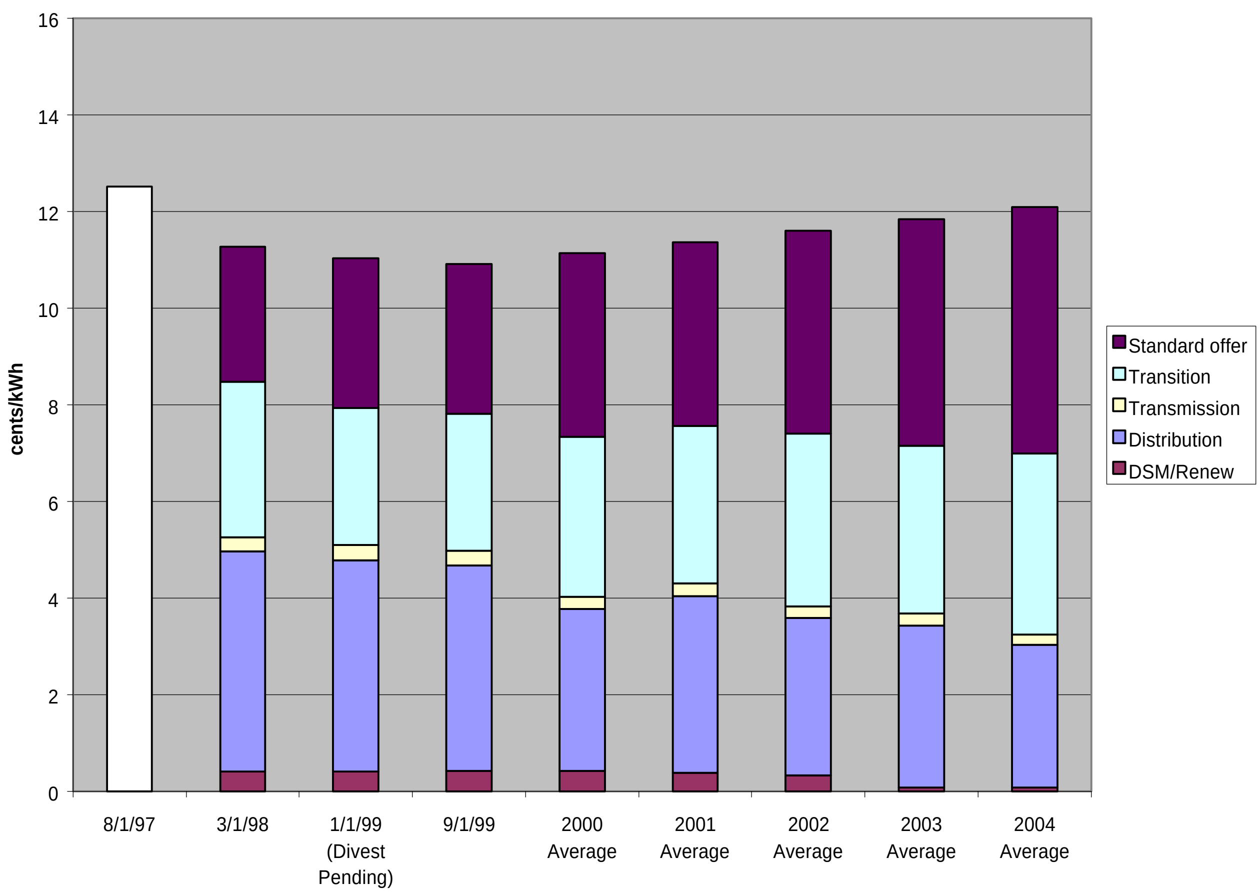
Sources: Distribution Rate Filings, DOER Forecasts



Western Massachusetts Electric

	8/1/97	3/1/98	Post-Divest (Pending)	9/1/99	2000 Avg.	2001 Avg.	2002 Avg.	2003 Avg.	2004 Avg.
Standard Offer		2.800	3.100	3.100	3.800	3.800	4.200	4.700	5.100
Transition		3.223	2.836	2.836	3.318	3.273	3.587	3.475	3.755
Transmission		0.283	0.318	0.310	0.245	0.267	0.237	0.245	0.215
Distribution		4.560	4.378	4.255	3.365	3.661	3.258	3.355	2.951
DSM/Ren.		0.405	0.405	0.41	0.41	0.37	0.325	0.075	0.075
Total	12.524	11.271	11.037	10.911	11.139	11.371	11.608	11.849	12.096

Sources: Distribution Rate Filings, DOER Forecasts



APPENDIX D

ISO-New England's Market Operations

The following are text excerpts and graphs are from ISO-New England's 1998 Annual Report, pages 14 and 15. It is a brief explanation of how the Bid-Based Market System will work.

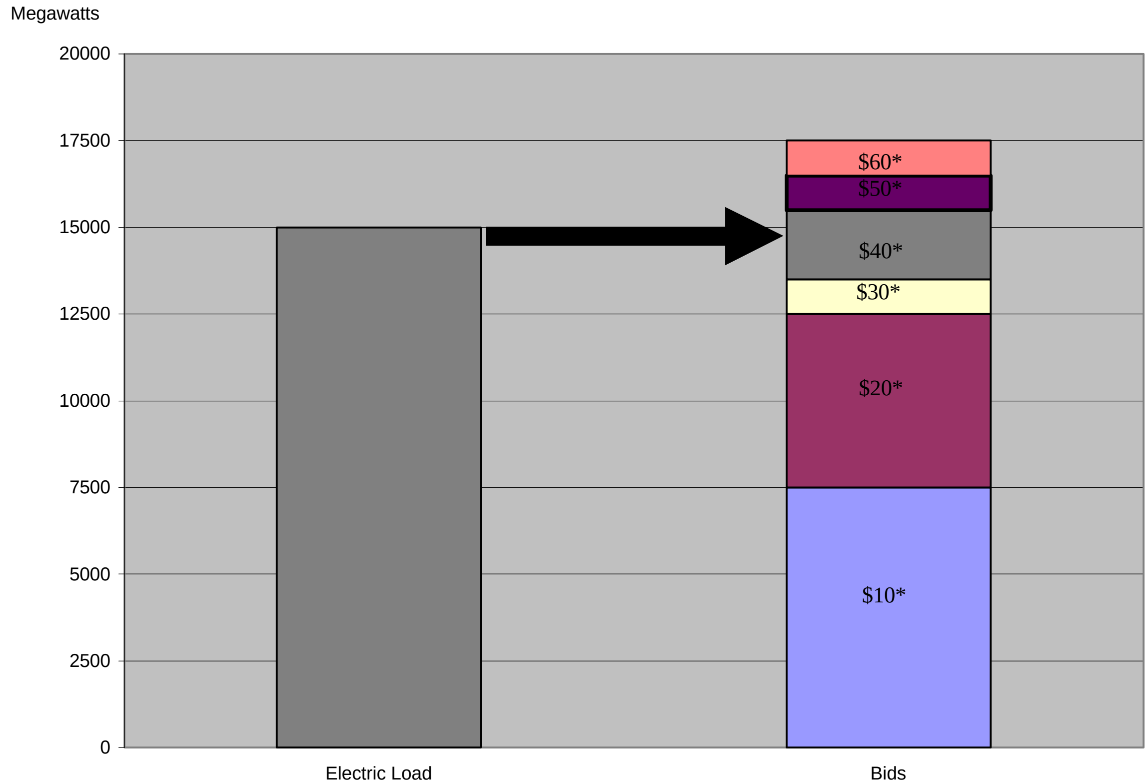
Seven Products

Because electricity is an unusual commodity – it can't be stored and is considered a necessity – operating reliability standards have played an important role in defining the products offered to the marketplace. Traditionally, operating reliability standards of New England's bulk power system have followed both Northeast Power Coordinating Council and NEPOOL requirements. These requirements led NEPOOL participants over the past three decades to build and maintain a mix of generating unit types, from quick start dispatch (Ten Minute Spinning Reserve) to longer term dispatch (Thirty Minute Operating Reserve). Six of the seven wholesale electricity products are an outcome of these requirements and are considered reliability markets. The seventh is the energy – or spot – market. (See Table).

The Seven Market Products

Name	Type of Product	Bidding Cycle	Time Period
Energy (spot)	Energy	Daily	Hourly
Installed Capacity (ICAP)	Capability	Monthly	
Operable Capacity (OPCAP)	Capability	Daily	Hourly
Ten Minute Spinning Reserve (TMRS)	Ancillary Service	Daily	Hourly
Ten Minute Non-Spinning Reserve (TMNSR)	Ancillary Service	Daily	Hourly
Thirty Minute Operating Reserve (TMOR)	Ancillary Service	Daily	Hourly
Automatic Generation Control	Ancillary Service	Daily	Hourly

Generator owners will submit bids for the amount of electricity offered to the marketplace and a price. All the bids are received and then ranked – or stacked – by ISO-New England form lowest to highest price. The real time marginal price (RTMP) will be determined by matching ISO-New England's projected demand with the corresponding bid stack. (See Figure D.1).



Source: ISO New England, Inc., 1998 Annual Report, p. 15.

Figure D.1: Clearing Price Per Hour

The generating units that bid below and up to the price corresponding to load demand will be told to run and will be included in the unit commitment for the following day. This bidding principle will be used for all seven wholesale electricity products.

All products are bought and sold daily, by the hour, with the exception of installed capability, which is a monthly market. Bids by market participants will be submitted by noon the day before the dispatch. ISO-New England will accept and stack bids and match them to forecasted electricity usage. ISO-New England will then notify generators whether or not their bids were accepted by 5:00 p.m. the same day, and those selected will receive dispatch instructions for the following day.

In the past, all NEPOOL members were accountable for ensuring overall reliability of the bulk power generation and transmission systems. This accountability took the form of the six reliability markets: ICAP, OPCAP, TMSR, TMNSR, TMOR, AGC. All members, proportionate to load, were responsible for each one of these reliability mechanisms. With the change to the bid-based market environment, responsibility will fall onto the market participants considered to be Load Serving Entities (LSEs). These companies will have to purchase these reliability products proportionate to the size of their load.

APPENDIX E -- NEPOOL Participants*

AllEnergy Marketing Co., L.L.C.
Alternate Power Source, Inc.
Aquila Power Corporation
Ashburnham Municipal Light Plant
Bangor Hydro-Electric Company
Belmont Municipal Light Department
Berkshire Power Development, Inc.
Boston Edison Company
Boylston Municipal Light Department
Braintree Electric Light Department
Central Maine Power Company
Chicopee Municipal Lighting Plant
CinCap IV, LLC
Cinergy Capital & Trading
Cinergy Services, Inc. Companies
The Cincinnati Gas & Electric Company, Inc.
PSI Energy, Inc.
Citizens Lehman Power Sales
Columbia Energy Power Marketing Corp.
COM/Energy Marketing, Inc.
Commonwealth Energy System Companies
Cambridge Electric Light Company
Canal Electric Company
Commonwealth Electric Company
Concord Municipal Light Plant
Con Edison Solutions
Consolidated Edison Co. of NY, Inc.
Connecticut Municipal Electric Energy Cooperative
Constellation Power Source, Inc.
Coral Power, L.L.C.
CSW Energy Services, Inc.
Danvers Electric Department
Dighton Power Associates Limited Partnership
Duke Energy Power Services, Inc.
Duke Energy Trading & Marketing, L.L.C.
Duke/Louis Dreyfus LLC
Eastern Utilities Associates Companies
Blackstone Valley Electric Company
Eastern Edison Company
Montaup Electric Company
Newport Electric Corporation
Electric Clearing House, Inc.
EnergyEXPRESS, Inc.
EnergyVision LLC
Energy Atlantic, LLC
Energy New England LLC
Engage Energy US, L.P.
ENRON Power Marketing, Inc.
Enserch Energy Services, Inc.
e prime, inc.
Fitchburg Gas and Electric Light Company
FPL Energy, Inc.
Georgetown Municipal Light Department
Great Bay Power Corporation
Griffin Energy Marketing, L.L.C.
Groton Electric Light Department
Hingham Municipal Lighting Plant
Holden Municipal Light Department
Holyoke Gas and Electric Department
H.Q. Energy Services (U.S.) Inc.
Hudson Light and Power Department
Hull Municipal Lighting PlantIndeck Maine
Indeck Maine Energy, L.L.C.
Indeck-Pepperell Power Associates, Inc.
Ipswich Municipal Light Department
KOCH Power Services, Inc.
LG&E Power Marketing Inc.
Littleton Electric Light and Water Department
Mansfield Municipal Electric Department
Marblehead Municipal Light Department
Mass. Municipal Wholesale Electric Company
Middleborough Gas and Electric Department
Middleton Municipal Electric Department
Milford Power Limited Partnership
Morgan Stanley Capital Group, Inc.
Narragansett Electric Company, The
New Energy Ventures L.L.C.
New England Electric System Operating Companies
Granite State Electric Company
Massachusetts Electric Company
New England Power Company
New Hampshire Electric Cooperative, Inc.
Niagara Mohawk Energy Inc. Companies
Niagara Mohawk Energy, Inc.
Niagara Mohawk Energy Marketing, Inc.
NorAm Energy Services, Inc.
North American Energy Conservation, Inc.
North Attleborough Electric Department
Northeast Energy Services, Inc.
Northeast Utilities System Companies
The Connecticut Light and Power Company
Holyoke Power and Electric Company
Holyoke Water Power Company
Public Service Company of New Hampshire
Western Massachusetts Electric Company
Norwood Municipal Light Department
NP Energy Inc.
Pascoag Fire District - Electric Department
Paxton Municipal Light Department
Peabody Municipal Light Plant
PEC Energy Marketing
PECO Energy Company
Pennsylvania Power & Light Co.
PG&E Energy Services
PG&E Energy Trading Power, L.P. Companies
PG&E Energy Trading, L.P.
USGen New England, Inc.
PSEG Energy Technologies Inc.
Public Service Electric and Gas Co.
Reading Municipal Light Department
Rowley Municipal Lighting Plant
Select Energy Inc.
Sempra Energy Trading Corp.
Shrewsbury Electric Light Plant
Sithe New England Holdings LLC
Sonat Power Marketing L.P.
South Hadley Electric Light Department
Southern Company Energy Marketing, L.P.
Statoil Energy Trading, Inc.
Sterling Municipal Electric Light Department
Strategic Energy, Limited Partnership
Taunton Municipal Lighting Plant
Templeton Municipal Lighting Plant
Tractebel Energy Marketing, Inc.
TransCanada Companies
TransCanada Energy Ltd.
TransCanada Power Marketing Ltd.
The United Illuminating Company
UNITIL Services Corporation Participant Companies
Concord Electric Company
Exeter & Hampton Electric Company
UNITIL Power Corp.
UNITIL Resources, Inc.
Vermont Electric Power Company, Inc.
Barton Village, Inc.
City of Burlington Electric Department
Central Vermont Public Service Corporation
Citizens Utilities Company
Village of Enosburg Falls Water & Light Department
Green Mountain Power Corporation
Village of Hardwick Electric Department
Village of Hyde Park, Inc.
Village of Jacksonville
Village of Johnson Electric Light Department
Village of Ludlow Electric Light Department
Village of Lyndonville Electric Department
Village of Morrisville Water & Light Department
Village of Northfield Electric Department
Village of Orleans Electric Department
Village of Readsboro Electric Light Department
Rochester Electric Light & Power Co.
Village of Stowe Water & Light Department
Village of Swanton
Vermont Electric Cooperative, Inc.
Vermont Marble Company
Vermont Public Power Supply Authority
Washington Electric Cooperative, Inc.
Vitol Gas & Electric Power Company
Wakefield Municipal Light Department
West Boylston Municipal Lighting Plant
Westfield Gas & Electric Light Department
Williams Energy Services Co.
XENERGY, Inc.

* As of December 31, 1998

Source: NEPOOL, "1998 NEPOOL Annual Report, back inside cover.

APPENDIX F

Proposed Generation Plants in New England

(estimates as of May, 1999)

Project	Owner	City/Town	State	Size	Type	Estimated On-line	
Bridgeport Harbor	Bridgeport Energy	**Bridgeport**	**CT**	520	G	Summer	1999
Lake Road Generating	Lake Road Gen	Killingly	CT	810	G	Summer	
Meriden Power	PDC	Meriden	CT	544	G		
Rocky River Power	Sempra	New Milford	CT	530	G		
AES Carpenter	AES	Southington	CT	700	G		
Wallingford Power	Wallingford Dept of Util	Wallingford	CT	550	G		
Milford Power	PDC	Milford	CT	540	G	Winter	2000/2001
S. Norwalk Pwr Project	GKO Inc.	S. Norwalk	CT	175	G	Winter	2000/2001
Haddam Station 1	Bechtel	Haddam Neck	CT	900	G		2001/2002
Towantic Energy	Arena Capital	Oxford	CT	540	G		2001/2002
Cross Sound Cable	TransEnergie	New Haven	CT	600	T		2002
Norwich Power Station	CT Muni Elec	Norwich	CT	500	G		2002
Versaille Energy Center	*SkyGen*	*Versaille*	*CT*		*G*	*Withdrawn*	
Haddam Station 2	*CY Atomic Pwr*	*Haddam Neck*	*CT*		*G*	*Withdrawn*	
Housatonic Power	*Tractebel*	*Sherman*	*CT*		*G*	*Withdrawn*	
WEG Norwich	*Williams*	*Norwich*	*CT*		*G*	*Withdrawn*	
				6909			
EMI-Dighton	EMI	Dighton	MA	185	G	Summer	1999
Berkshire Power	PDC	Agawam	MA	276	G	Winter	1999/2000
Millennium	US Gen	Charlton	MA	400	G	Summer	
Cabot Power	Cabot Power	Everett	MA	350	G	Summer	
ANP Bellingham	ANP	Bellingham	MA	580	G	Winter	2000/2001
ANP Blackstone	ANP	Blackstone	MA	580	G	Winter	2000/2001
Patriot Cabot Street Sta.	Patriot Power	Holyoke	MA	300	G		2000/2001
FPL Energy	ESI New Bedford	New Bedford	MA	250	G		2000/2001
Mystic Expansion	Sithe	Charlestown	MA	1750	G		
Canal Unit 3	Southern	Sandwich	MA	561	G		
Brayton Point 5	US Gen	Swansea	MA	477	G	Summer	
Medway Expansion	Sithe	W. Medway	MA	540	G		
Summit Power	PDC	Westfield	MA	276	G	Summer	
Edgar Expansion	Sithe	Weymouth	MA	1500	G		
Brockton Power Project	Brockton Pwr	Brockton	MA	272	G		2001
Kendall Repowering	Southern	Cambridge	MA	172	G		2001
Nickel Hill	Constellation	Dracut	MA	750	G		2001
Glen Charlie One	B-W Energy	Wareham	MA	500	G		2001
IDC Bellingham	IDC	Bellingham	MA	700	G		2001/2002
Campello Power	Generation Venture	Brockton	MA	285	G		2002
Patriot Power	*Duke*	*Taunton*	*MA*			*Withdrawn*	
S&P Cogeneration	*W. Lynn Creamery*	*Lynn*	*MA*			*Withdrawn*	
Wareham	*EMI*	*Wareham*	*MA*			*Withdrawn*	
Framingham Expansion	*Sithe*	*Framingham*	*MA*			*Withdrawn*	
				10704			

Project	Owner	City/Town	State	Size	Type	Estimated On-line	
Androscoggin Energy Center	SkyGen	Jay	ME	157	G	Winter	1999/2000
Bucksport Energy	P,F,B&P	Bucksport	ME	174	G	Summer	2000
ME Independence	Casco Bay Energy	Veazie	ME	500	G	Summer	2000
Engage Energy LT Firm PtP In	Engage Energy	NB-MEPCO	ME	300	T		2000
ANP Gorham	ANP	Portland	ME	850	G		2000
Rumford Power	EMI	Rumford	ME	265	G	Summer	2000
Westbrook Power	Westbrook Pwr	Westbrook	ME	520	G	Summer	2000
Mason	FPL Energy	Wiscasset	ME	550	G		2000
Wyman A	FPL Energy	Yarmouth	ME	550	G		2000
Orrington Generation	Orrington Gen	Orrington	ME	700	G		2001
Wiscassett	Stone & Webster	Wiscassett	ME	1400	G		2001
Irving Oil LTF PtP	Irving Oil	NB-MEPCO	ME	250	T		2001
Redington Mt. Wind Farm	Redington Wind	Carrabassett	ME	30	G		2002
Tractebel LT Firm PtP In	Tractebel	NB-NEPOOL	ME	300	T		2002
Tractebel LTF Int+Internal PtP	Tractebel	NB-NEPOOL	ME	600	T		
HQ-Surowiec, CMP HVDC	CMP	Pownal	ME	600	T		2002
Wyman B	*FPL Energy*	*Yarmouth*	*ME*		*G*	*Withdrawn*	
Livermore Falls	*SkyGen*	*Livermore*	*ME*			*Withdrawn*	
				7746			
Piscataqua Power	Tractebel	Newington	NH	700	G		2000
SEI Newington	Southern	Newington	NH	525	G	Summer	2000
AES Londonderry	AES	Londonderry	NH	742	G		2001
Newington Energy Center	Duke	Newington	NH	520	G		2001
White Mtn Cogen	*SkyGen*	*Groveton*	*NH*			*Withdrawn*	
				2487			
EMI-Tiverton	EMI	Tiverton	RI	265	G	Winter	2000/2001
R.I. Hope Energy	Houston Ind Power	Johnston	RI	500	G		
Tuspani Power	INDECK	N. Smithfield	RI	350	G		2001/2002
				1115			
HQ-Highgate2 HVDC	GMP	Highgate	VT	600	T		2001
Bennington Energy Park	VT Pwr & Dev	Bennington	VT	270	G		2001/2002
Rutland Energy Park	VT Pwr & Dev	Rutland	VT	1080	G		2001/2002
CVPS/GMP LT Firm PtP In	GMP	NY/VT	VT	600	T		2002
				2550			
Total New England Proposed Capacity				**31511**			

Source: ISO-New England website

APPENDIX G

Massachusetts Competitive Suppliers / Electricity Brokers

*****While these Competitive Power Suppliers/Electricity Brokers have indicated intent to serve residential customers, they are not offering residential service as of this date.

A "-1" under Res (Residential) Com (Commercial) or Ind (Industrial) indicates the market(s) that the supplier serves

Status	Type	Company	Res	Com	Ind	City	Phone	Licensed	License #
APPROVED LIST	COMPETITIVE SUPPLIERS	All Energy Marketing . Company. L.L.C.	-1	-1	-1	Waltham	1-888-643-9502	4/9/98	CS-005
APPROVED LIST	COMPETITIVE SUPPLIERS	Alternate Source, Inc.	0	-1	-1	Westwood	1-877-773-0344	10/27/98	CS-016
APPROVED LIST	COMPETITIVE SUPPLIERS	Duke Solutions, Inc.	0	-1	-1	Charlotte	1-800-943-7578	6/9/98	CS-009
APPROVED LIST	COMPETITIVE SUPPLIERS	Energy Vision, L.L.C.	0	-1	-1	Burlington	1-888-671-1212	3/19/98	CS-002
APPROVED LIST	COMPETITIVE SUPPLIERS	Enron Energy Services	0	-1	-1	Houston	1-800-837-9584	8/14/98	CS-014
APPROVED LIST	COMPETITIVE SUPPLIERS	Enserch Energy Services	0	-1	-1	Providence	1-800-558-2486	6/25/98	CS-013
APPROVED LIST	COMPETITIVE SUPPLIERS	Horizon Energy Company d/b/a Exelon Energy	-1	-1	-1	Philadelphia	1-888-551-4332	4/9/98	CS-004
APPROVED LIST	COMPETITIVE SUPPLIERS	NEV East, L.L.C.	0	-1	-1	Boston	1-888-802-8998	10/27/98	CS-015
APPROVED LIST	COMPETITIVE SUPPLIERS	Northeast Energy Services, Inc. d/b/a NORESCO	-1	-1	-1	Framingham	1-888-5NORESCO	4/9/98	CS-006
APPROVED LIST	COMPETITIVE SUPPLIERS	PG&E Energy Services Corporation	0	-1	-1	San Fransico	1-888-743-4178	5/15/98	CS-007
APPROVED LIST	COMPETITIVE SUPPLIERS	Reliant Energy Retail, Inc. (formerly NorAM Energy)	0	-1	-1	Houston	1-888-292-5720	6/9/98	CS-010
APPROVED LIST	COMPETITIVE SUPPLIERS	Select Energy, Inc.	-1	-1	-1	Berlin	1-800-789-2213	6/25/98	CS-011
APPROVED LIST	COMPETITIVE SUPPLIERS	TransCanada Power Marketing Ltd. ("TCMP")	0	-1	-1	Westborough	1-877-634-2928	1/14/99	CS-017
APPROVED LIST	COMPETITIVE SUPPLIERS	Unitil Resources, Inc.	-1	-1	-1	Hampton	1-888-864-7693	3/19/98	CS-001
APPROVED LIST	ELECTRIC BROKERS LICENSE	AEDR Fuels, L.L.C. d/b/a AllEnergy Heating Company	-1	-1	0	Waltham	1-888-643-9502	5/12/99	EB-011
APPROVED LIST	ELECTRIC BROKERS LICENSE	Aetna Corp, Inc.	0	-1	-1	Cambridge	1-800-544-4836	3/19/98	EB-002
APPROVED LIST	ELECTRIC BROKERS LICENSE	Affiliated Power Purchasers, Inc.	0	-1	-1	Salisbury	1-800-520-6685	5/12/98	EB-004
APPROVED LIST	ELECTRIC BROKERS LICENSE	Alternate Power Source, Inc.	0	0	0	Westwood	1-877-773-0344	6/23/98	EB-005
APPROVED LIST	ELECTRIC BROKERS LICENSE	Chamber Energy . Coalition, Inc.	-1	-1	-1	Springfield	1-888-844-8640	8/14/98	EB-008
APPROVED LIST	ELECTRIC BROKERS LICENSE	Energy Options Consulting Group. L.L.C.	0	-1	-1	Boston	1- 800-362-2603, 03	8/14/98	EB-006
APPROVED LIST	ELECTRIC BROKERS LICENSE	essential.com. inc.	-1	-1	0	Burlington	1-781-229-9599	5/20/99	EB-012
APPROVED LIST	ELECTRIC BROKERS LICENSE	John Howat Associates	-1	-1	-1	Boston	1-888-321-1141	8/14/98	EB-007
APPROVED LIST	ELECTRIC BROKERS LICENSE	National Energy. Choice, L.L.C.	0	-1	-1	Boston	1-888-772-9288	3/12/98	EB-001
APPROVED LIST	ELECTRIC BROKERS LICENSE	PECO Energy Co. d/b/a Exelon Mgmt & Consulting	-1	-1	-1	Philadelphia	1-888-841-6905	1/15/99	EB-009

Status	Type	Company	Res	Com	Ind	City	Phone	Licensed	License #
APPROVED LIST	ELECTRIC BROKERS LICENSE	TelEnergy, Inc.	-1	-1	-1	Newton	1-888-827-4433	3/19/98	EB-003
APPROVED LIST	ELECTRIC BROKERS LICENSE	Xenergy, Inc.	0	-1	-1	Burlington	1-800-810-1882	4/9/98	EB-010

Source: Department of Telecommunications and Energy website (www.state.ma.us/dpu/)